Methane Emissions Abatement Potential from Glycol Dehydration Processes in Canada's Upstream Oil & Gas Sector

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Executive Summary

Petroleum Technology Alliance Canada (PTAC) and the Alberta Upstream Petroleum Research Fund (AUPRF) engaged Process Ecology Inc. to undertake a study of the methane reduction abatement potential from glycol-based natural gas dehydration and refrigeration processes in the Canadian upstream oil & gas (UOG) sector.

The objectives of this work included the evaluation of alternative emissions estimation methodologies, determination of the key operating parameters that influence methane emissions, and identification of emissions reduction technologies applicable to these process units and their associated marginal abatement cost. The study involved a review of both glycol dehydration units (typically using triethylene glycol- TEG) and refrigeration plants (using ethylene glycol- EG). Primary data collection from UOG companies/facilities as well as secondary data collection from a number of other sources were used to inform the study results, including total installed costs and market penetration of emissions control technologies.

Key findings of the study include:

- The most widely used simulation software tools (Aspen HYSYS and GRI Glycalc) provide very similar predictions of methane emissions from these facilities. Some advantages were identified for the later versions of Aspen HYSYS (v9.0, 10.0) where the simulation model predicts dry gas water content with better accuracy than GRI GlyCalc. The "Glycol Property Package" in HYSYS has been identified as the best thermodynamics model to represent the TEG dehydration system. A modified "NRTL-Peng Robinson Property Package" in HYSYS has been determined as the best thermodynamic method to estimate emissions from EG refrigeration plants.
- Regarding the influence of operating parameters on methane emissions, for TEG dehydration plants, plant configuration characteristics such as the use of stripping gas and gas-driven pumps will significantly influence methane emissions. Parameters such as contactor temperature and pressure also influence methane emissions, although these parameters are generally not in the control of the operator. In general, facilities have control over glycol circulation rates (including changing the pump type/size), and the rate of stripping gas use. These key parameters can guide the implementation of control technologies for higher-pressure systems with gas driven pumps and stripping gas use, as these will be the largest emitters.
- It has been estimated that the potential for methane emissions reductions from glycol dehydration facilities in Western Canada is approximately 1.1 MT CO_2eq/yr and that these reductions can be achieved with low cost actions to reduce methane venting such as stripping gas reduction, glycol circulation optimization, and glycol pump replacements.
- Further emissions reductions can be achieved through the implementation of emissions control technologies. There are several control technologies available in the market. The choice of technology depends heavily on the specific characteristics of the facility including the availability of flare capacity, size of the operation, and other regulatory constraints.

- Process optimization methods such as circulation rate reduction, stripping gas reduction, and reboiler temperature optimization present opportunities for simultaneous emissions and cost reductions. These methods can be considered before technology installations which typically come with significant capital costs.
- Methane reduction potential and annualized costs were assessed for various technologies based on vendor estimates and actual installation experience in industry. Proprietary technologies that offer significant methane reduction at relatively low costs include vent gas capture which replaces fuel gas in the reboiler burner; however, care must be taken to ensure there is balance between available capture gas and reboiler burner requirements.

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1. Introduction

1.1. Background

The Government of Canada has recently released regulations to reduce methane emissions in the oil and gas sector by 40% to 45% below 2012 emissions by 2025.

Within Canada, the Province of Alberta has announced its own 45% methane reduction target from oil and gas operations, to be implemented by the Alberta Energy Regulator (AER) through improved measurement and reporting, regulated standards for existing facilities, and new design standards. Within Alberta, the majority (>86% in 2015) of sector methane emissions are from upstream oil and gas production, with the remainder coming from oil sands mining and upgrading (13%) and downstream refining and distribution (<1%). [1]

The upstream oil and gas industry relies on glycol dehydrators to remove water from natural gas. The dehydration process also helps to prevent corrosion and hydrate formation in pipelines. Industry surveys have identified about 4,000 glycol dehydrators in service in Canada. The majority of the units are installed in rural environments and are typically unmanned/unattended. A study by the Natural Gas Star Program (USEPA) reports approximately 36,000 glycol dehydration systems in the US natural gas production sector [2].

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) such as benzene, toluene, ethylbenzene and xylenes (BTEXs). As TEG is regenerated through heating in a reboiler, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, creating a significant source of methane emissions.

Due to its potent global warming potential, methane is receiving significant regulatory focus both within the oil and gas industry and in other sectors. The current state of regulation in Alberta and Canada (federally) is summarized next.

<u>a. Alberta:</u>

Alberta has stated a goal to reduce methane emissions from oil and gas operations by 45 percent (from a 2012 baseline) by 2025. New regulations have been released as part of Directive 60 and Directive 39. In short, there will be vent gas limits for:

- Pneumatic devices
- Compressor seals
- Glycol Dehydrators
- Fugitive Emissions

By January 1, 2020:

- a Methane Reduction Retrofit Compliance Plan (MRRCP) must be completed, which must at a minimum contain the schedule to replace or retrofit existing equipment
- a Fugitive Emissions Management Plan (FEMP) must be documented

b. Federal:

Canada intends to reduce methane emissions from oil and gas operations and will include that reduction in the promised national reduction of methane by 40-45 percent (below 2012 levels) by 2025. This will be regulated under the Canadian Environmental Protection Act (1999). Regulations have focused on the main sources of methane venting, which includes dehydration plants.

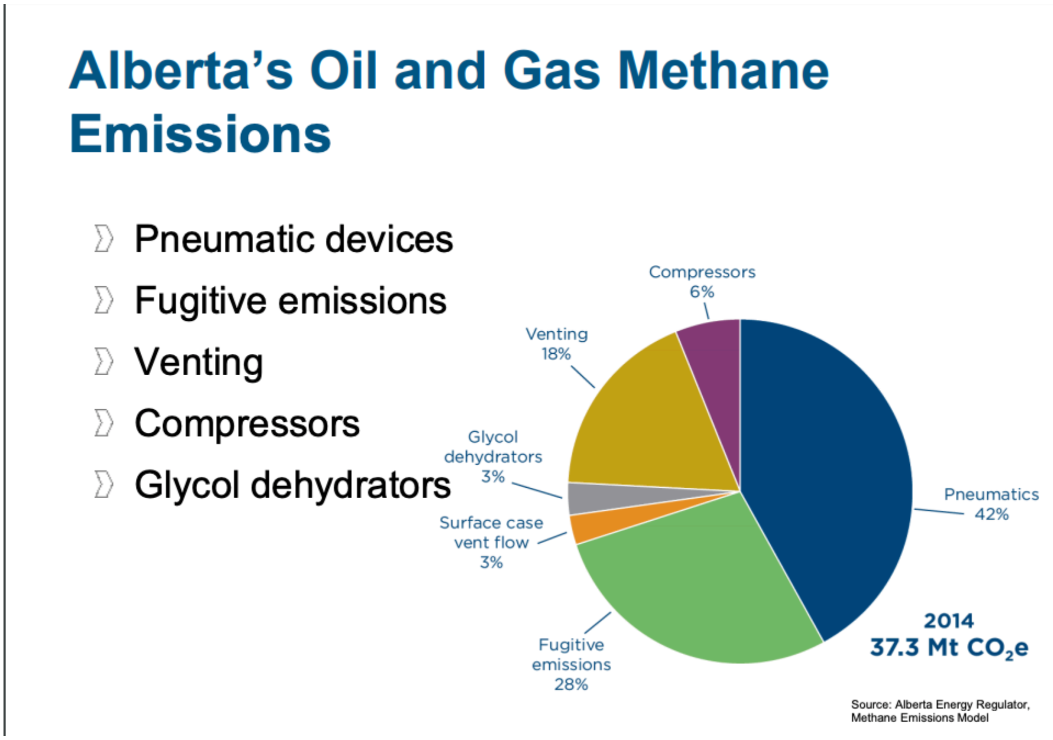

Figure 1 Methane Emissions from Alberta's UOG

Glycol dehydrators have been identified as a significant opportunity for methane emissions reductions in Alberta as these emissions sources offer relatively simple operating changes or retrofit opportunities that can deliver significant emissions reductions.

1.2. Study Objectives, Scope, and Deliverables

The primary objectives of this study are:

- To evaluate emissions estimation methodologies for methane venting from glycol dehydration and refrigeration plants and provide recommendations for further modelling work.
- To determine the main operating parameters that influence methane emissions from these facilities.
- To identify currently available best practices and emissions control technologies and average abatement cost profiles.

The outcome of this work is to assist the upstream oil & gas industry in identifying opportunities for methane emissions reductions at their facilities in a cost-efficient manner.

1.3. Report Organization

The remainder of this report is structured as follows:

- Review and conclusions of available emissions estimation methodologies
- Sensitivity analysis for key parameters which influence methane emissions in glycol dehydration and refrigeration facilities
- Description of control technologies applicable to glycol regenerator venting
- Economic analysis and marginal abatement cost curves for key selected technologies
- Conclusions and recommendations for future work

2. Review of Methane and CO2 Emissions Estimation Methods in Gas Dehydration and Refrigeration Facilities

2.1. Overview

There are different methods for estimating methane and CO_2 emissions from gas dehydration and refrigeration facilities where triethylene glycol (TEG) and ethylene glycol (EG) are used respectively to separate water from wet gas. GRI-Glycalc and Aspentech HYSYS are two simulation software tools widely used to estimate BTEX emissions from gas processing facilities. In this report, we investigate the ability of both simulation software applications in estimating **methane** and **CO_2** emissions from dehydration and refrigeration facilities. In addition, we also investigate a new correlation approach developed by Process Ecology to estimate methane and CO_2 emissions from these facilities. Figure 2 shows the sources of emissions from a typical TEG dehydration unit. Most of the emissions are from the glycol regenerator, which go directly to the atmosphere if no emission controls are installed. If a flash tank is installed, the vapors are also emitted to the atmosphere if not controlled.

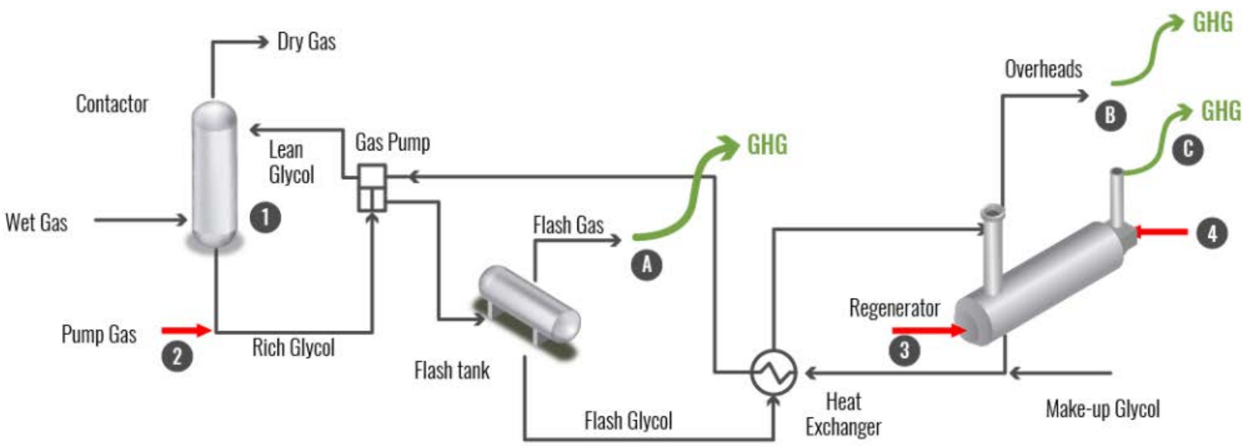

Figure 2 Sample PFD for TEG dehydration unit with a flash tank separator

The accuracy of methane and CO_2 emissions estimates depends on the capability of each method to correctly predict the vapor-liquid equilibrium (VLE) of a mixture that contains water, glycol (TEG or EG), methane, and other hydrocarbon components at the contactor or low-temperature separator (LTS) conditions. Most of the methane and CO_2 in the liquid phase of the mixture at the contactor outlet (i.e., rich glycol stream) or LTS aqueous phase outlet is eventually emitted from the flash tank (if installed) and the glycol regenerator still vent. Therefore, in this report we first compare the equilibrium data predicted by each method to available experimental data. Then, emissions estimates for a selected group of TEG (22 cases) and EG (8 cases) facilities are obtained using different methods and are compared to understand whether there are significant differences between emissions estimates. Finally, emissions estimates for 12 TEG and EG facilities are compared to the results of total capture test (TCT) reports as directly measured at various facilities in Alberta.

According to the vapor-liquid equilibrium (VLE) data comparison, a HYSYS simulation using the Glycol Property (GP) package is capable of predicting methane solubility in TEG with high accuracy and which decreases slightly with increased water content of the mixture. Comparing simulation results to the experimental data presented in GPA RR-131 [3] shows that HYSYS GP can predict the solubility of methane in the liquid phase with high precision (less than 10% error) particularly for systems with **lower water content** and at **lower pressures**. The results also show that the **Glycol Package in HYSYS V9-10 (GP9-10) improves the methane solubility prediction compared to HYSYS V7.0 (GP7)** at all pressure and temperature conditions.

Overall, Glycalc results are the closest fit to RR-131 data for methane equilibrium concentration in wet gas and TEG mixtures. However, the **differences between Glycalc and HYSYS GP9-10 predictions are marginal** in most cases.

At higher water contents and higher pressures at the contactor, the Peng-Robinson property package in HYSYS delivers slightly better predictions compared to GP10. However, when considering the various sources of methane (contactor, flash tank, still vent) GP10 performs better overall.

It should be noted that these conclusions are made based on a limited set of experimental data. If a wider set of experimental data becomes available in the literature, more reliable conclusions can be made about different simulation methods.

When comparing emissions estimates from TEG dehydration facilities, we conclude that in most cases there are **no significant differences between the estimated emissions using the different methods reviewed**. In 80% of the TEG cases investigated in this study, the largest difference between estimated methane emissions is less than 1 lb/hr (4 tonnes/yr). According to these results, both HYSYS simulations (GP9-10) and Glycalc show good results for methane and CO_2 emissions. **A correlation method developed by Process Ecology provides estimates of methane emissions which match HYSYS results with reasonable accuracy (less than 5% error) in 90% of cases**. The advantage of using the correlation method is that it is a much simpler and a more efficient calculation approach.

A HYSYS simulation has some important advantages over Glycalc including better prediction of dry gas water content which is an essential parameter to evaluate unit performance and optimization. HYSYS also enables greater flexibility in process configurations and in the ability to easily test estimation results under various conditions and compare them to available experimental data.

For refrigeration facilities, the NRTL-PR property package (with adjusted parameters by Process Ecology) seems to be the most reliable method as it can consistently predict two liquid phases at various low temperature separator (LTS) conditions. Both Glycalc and HYSYS GP are not always able to predict both aqueous and liquid hydrocarbon phases at LTS conditions which results in inaccurate emissions estimates.

Comparing simulation results to total capture test (TCT) measured emissions is not conclusive. In two out of the twelve cases reviewed, TCT emissions are significantly higher than the results of all simulation methods. This could be due to measurement errors at the facility. In most of the remaining cases, simulation methods have similar emissions estimates and consequently, similar errors compared to TCT results. In three cases, Glycalc estimates are slightly closer to TCT emissions compared to HYSYS GP9-10. As more TCT reports with reliable results become available, a comparison to a larger number of cases can be completed and better conclusions reached. In summary, the tested simulation models agree with trends in measured emissions although some cases display significant deviations.

Overall, the study indicates that both Glycalc and HYSYS GP9-10 are reliable estimation methods for methane emissions from glycol dehydration and that HYSYS NRTL-PR delivers more accurate and consistent estimation of methane emissions for EG refrigeration plants.

2.2. Introduction

In this section we investigate the accuracy of methane and CO_2 emissions estimates from gas dehydration and refrigeration facilities that are obtained by several different approaches: HYSYS simulation, GRI-Glycalc, and correlation analysis.

The correlation analysis was developed by Process Ecology in 2015 to estimate emissions from dehydration and refrigeration facilities using key plant parameters (e.g., inlet gas flowrate and composition, contactor pressure and temperature, glycol circulation rate, etc.). In this method, multivariate statistical analysis was performed on a set of input data from dehydration and refrigeration facilities and their corresponding estimated emissions using HYSYS simulation. A series of nonlinear regression models were built to generate emissions estimates close to HYSYS predicted emissions. The objective of the correlation model is to reproduce HYSYS outputs in a simple and less rigorous way that does not require a HYSYS simulation.

Triethylene glycol (TEG) and ethylene glycol (EG) are used in gas dehydration and refrigeration facilities, respectively, to facilitate the separation of water from gas. The accuracy of methane and CO_2 estimates depends on the capability of the methods to correctly predict the vapor-liquid equilibrium (VLE) of a mixture that contains water, glycol (TEG or EG), methane, and other hydrocarbon components.

In this section, first VLE data from computer simulations are compared to existing experimental data to examine the accuracy of phase equilibrium predictions by Glycalc and different thermodynamic models (property packages) in HYSYS. Then, we present a comparison of emissions estimates for a group of dehydration and refrigeration facilities using HYSYS simulation with alternative thermodynamic models (Peng-Robinson (PR), NRTL-PR and Glycol Property (GP) package), the GRI-Glycalc software, and the correlation approach (used in Process Ecology's Methane Emissions Advisor software). Finally, emissions estimates by HYSYS and Glycalc are compared with available data from total capture test (TCT) reports for a group of facilities. We also note that the similarities in methane emissions between GP in HYSYS v9 and v10 are negligible, so they are dealt with as a single option throughout the report.

2.3. Vapor-liquid equilibrium (VLE) data comparison

The accuracy of emissions estimates from different methods is closely related to the accuracy of methane equilibrium concentrations in the wet gas and glycol mixture (i.e., the concentration of methane in the rich glycol stream at the contactor or the low temperature separator (LTS) outlet). Therefore, achieving more accurate emissions estimates requires a more accurate prediction of vapor-liquid (VLE) or vapor-liquid-liquid (VLLE) equilibrium of these systems. Unfortunately, experimental data for VLLE of gas and EG mixtures at LTS conditions are not available in the literature for comparison.

2.3.1. GPA RR-131 data

The most comprehensive data source for vapor-liquid equilibrium of wet natural gas (NG) and glycol mixtures is the GPA Research Report RR-131 [3]. The available measured data for solubility of methane in the mixture can be compared with the results of simulation methods. We use the data in RR-131 and compare it to the results of HYSYS Peng-Robinson (PR), HYSYS V9-10 Glycol Package (GP9-10), HYSYS V7.0 Glycol Package (GP7), and partially to the results of Glycalc. A full comparison to Glycalc is not possible as the software does not allow for direct input of feed compositions to the flash tank and the regenerator, therefore, it is not possible to reach the exact composition used in RR-131 at these conditions.

The results of these comparisons are shown in Figure 3 and Table 2. Temperature and pressure conditions used for the comparison are shown in Table 1 (x-axis in Figure 3). According to Figure 3 and Table 2, Glycalc results for methane concentration show the closest match to the experimental data (for those cases where Glycalc results are available). However, the methane concentrations predicted by HYSYS GP9-10 in most cases are very close to experimental data as well. The concentration prediction errors compared to experimental data for all cases and all methods are presented in Table 2. The results show that at lower pressures and lower water content in the mixture, HYSYS GP9-10 can predict the solubility of methane in the liquid phase of the wet gas and glycol mixture with high precision (less than 10% error). The results also show that Glycol package in HYSYS V9-10 (GP9-10) improves the methane solubility prediction compared to HYSYS V7.0 (GP7) at all pressure and temperature conditions. The last two cases (11 and 12) refer to streams at regenerator conditions which explains the significantly lower reported methane concentrations.

Comparing PR and GP9-10 results show that at higher pressure at the contactor and higher water content in the mixture, methane solubility predicted by PR is closer to experimental values. However, GP9-10 shows better predictions at lower water content and lower pressure in the contactor and at flash tank and regenerator conditions compared to PR.

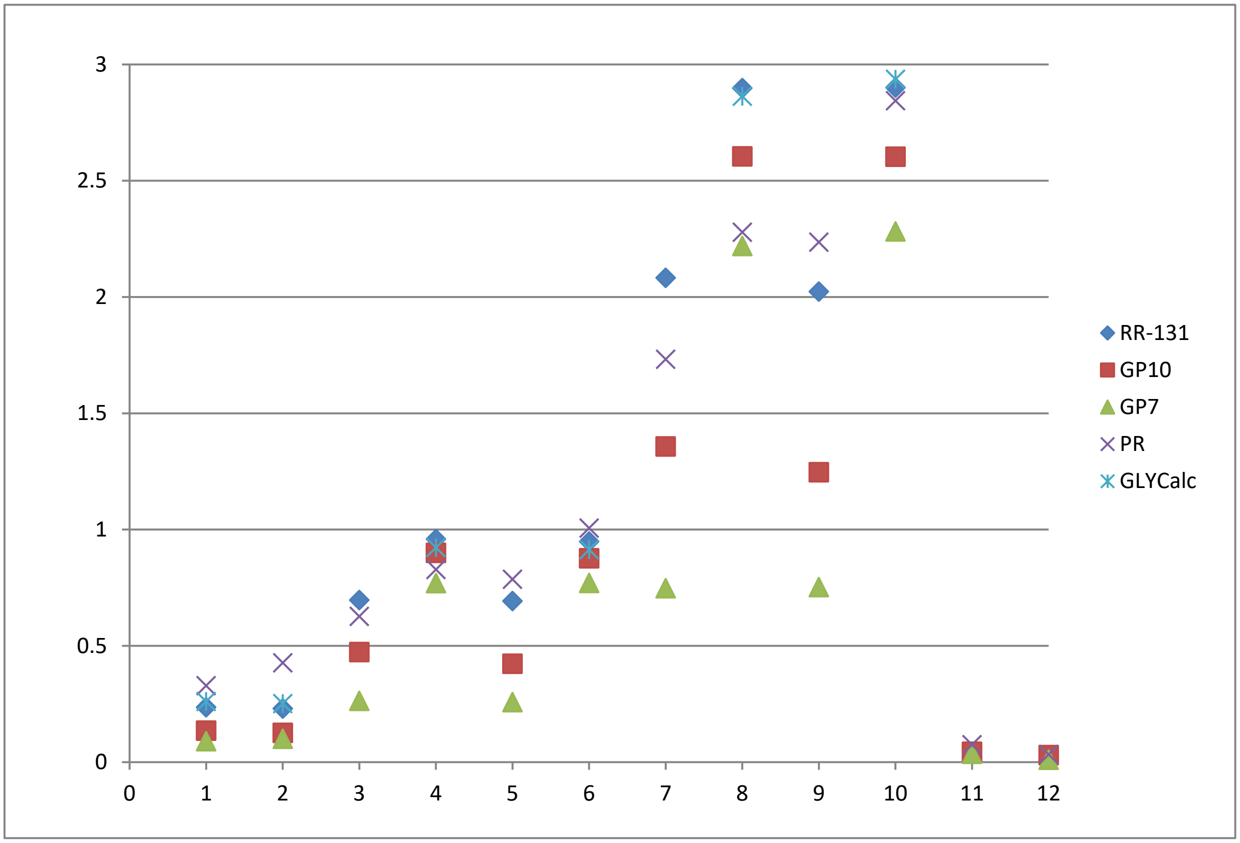

Figure 3 GPA RR-131 experimental data comparison with simulation results for methane concentration in rich glycol stream (mole %)

Table 1 GPA RR-131 cases information

Cases	T (F)	P (psig)	wt% of water	Process unit
1	167	100	5	Flash tank
2	257	100	5	Flash tank
3	77	300	5	Contactor
4	77	300	1	Contactor
5	122	300	5	Contactor
6	122	300	1	Contactor
7	77	1000	5	Contactor
8	77	1000	1	Contactor
9	122	1000	5	Contactor
10	122	1000	1	Contactor
11	350	21.8	1	Regenerator
12	400	23.5	1	Regenerator

Table 2 Methane concentration data comparison with RR-131

Cases	Percent error in methane concentration prediction compared to experimental data (RR-131)			
	GLYCalc	GP7	GP9-10	PR
1	10.5%	61.6%	42.6%	39.4%
2	9.4%	56.2%	45.1%	85.4%
3	-	62.2%	32.0%	10.0%
4	3.8%	19.7%	6.2%	13.6%
5	-	62.8%	39.0%	13.4%
6	3.7%	18.7%	7.6%	6.1%
7	-	64.1%	34.8%	16.8%
8	1.2%	23.4%	10.1%	21.4%
9	-	62.8%	38.4%	10.5%
10	1.2%	21.3%	10.3%	1.9%
11	-	19.8%	1.0%	65.6%
12	-	62.5%	6.7%	15.4%

2.3.2. Binary mixture solubility data

Other experimental data sources found in the literature usually include VLE data for binary mixtures only. Here we compare HYSYS V7.0 and V9-10 Glycol package VLE data for a methane-TEG binary mixture with experimental data presented in [4]. Pressure vs methane mole fraction at 5 different temperatures are presented and compared in Figures 32 to 36 in Appendix A. As shown in these figures, GP package in all versions of HYSYS can accurately predict methane concentration in glycol at various temperatures and pressures. However, at very high pressures HYSYS shows slightly higher concentration of methane compared to experimental data.

2.4. Comparison of estimated emissions for dehydration and refrigeration facilities

2.4.1. TEG Dehydration

In this section Triethylene Glycol (TEG) dehydration facilities are investigated. Operating data from 22 different TEG facilities were collected and used in the comparison. The 22 facilities (shown in Table 3) were selected from among more than 400 TEG facilities available in the Process Ecology Benzene Emissions Advisor database for different dehydration process configurations, i.e., based on:

- Temperature and pressure of the contactor
- Type of pump used for glycol recirculation (gas pump or electric pump),
- Presence of a flash tank,
- Use of stripping gas for glycol regeneration

It is noted that no identifying information (client, facility, location) is used in the analysis, which identifies facilities only as "Case 1", "Case 2", etc.

Four different methods were used to estimate methane and CO_2 emissions for these 22 facilities:

- ASPEN HYSYS V10 simulation- using Peng-Robinson property package (PR)
- ASPEN HYSYS V10 simulation- using Glycol property package (GP9-10)
- ASPEN HYSYS V7.0 simulation- using Glycol property package (GP7)
- GRI Glycalc software

Results of TEG units emissions estimates (methane emissions in Table 15 and Figures 4, Figure 37-38, CO_2 emissions in Table 16 and Figures 5, Figure 39-40) show that the estimated overall methane and CO_2 emissions using these five different methods are very close in most cases. In 17 out of 22 cases, the largest difference between methane emissions estimates from different methods is less than 1 lb/hr (less than 3.9 tonnes/year). In 15 out of 22 cases, the largest difference between CO_2 emissions estimates is less than 0.5 lb/hr.

Based on these results, it is noted that the highest differences in methane emissions estimates correspond to units with relatively high contactor pressure. It should also be noted that the source of these differences in total methane emissions estimates is due to the predicted concentration of methane in the rich glycol stream at the contactor outlet (other sources of methane emissions are the gas pump and stripping gas which are set to equal values in all methods). As a result, predicting the methane concentration in the rich glycol stream with high accuracy is the key challenge to achieve accurate emissions estimates in TEG facilities.

In the CO_2 emissions estimates comparison presented in Table 16, there is one case (case 14), with significantly higher CO_2 emissions than other cases. The reason is that in this case, acid gas is processed in the dehydration facility and has been removed from Figure 39 to enable a better comparison.

Table 3 TEG cases selected for emissions estimates comparison

Case	Pump type	Flash tank	Stripping gas	Contactor T (°C)	Contactor P (kPag)
Case 1	Gas	Yes	Dry gas	25	2068.4
Case 2	Gas	Yes	Dry gas	25	6000
Case 3	Gas	Yes	Flash gas	26	7300
Case 4	Gas	Yes	No	28	2150
Case 5	Gas	Yes	No	30	7800
Case 6	Gas	No	Dry gas	20	551.6
Case 7	Gas	No	Dry gas	26	5200
Case 8	Gas	No	No	18	930.8
Case 9	Gas	No	No	10	6142
Case 10	Electric	Yes	Dry gas	22	2300
Case 11	Electric	Yes	Dry gas	32	8900
Case 12	Electric	Yes	Flash gas	30	4000
Case 13	Electric	Yes	No	16	524
Case 14	Electric	Yes	No	30	2300
Case 15	Electric	Yes	No	30	3700
Case 16	Electric	Yes	No	30	6600
Case 17	Electric	No	Dry gas	35	750
Case 18	Electric	No	Dry gas	12	2300
Case 19	Electric	No	Dry gas	30	4500
Case 20	Electric	No	No	15	800
Case 21	Electric	No	No	20	2000
Case 22	Electric	No	No	22	5500

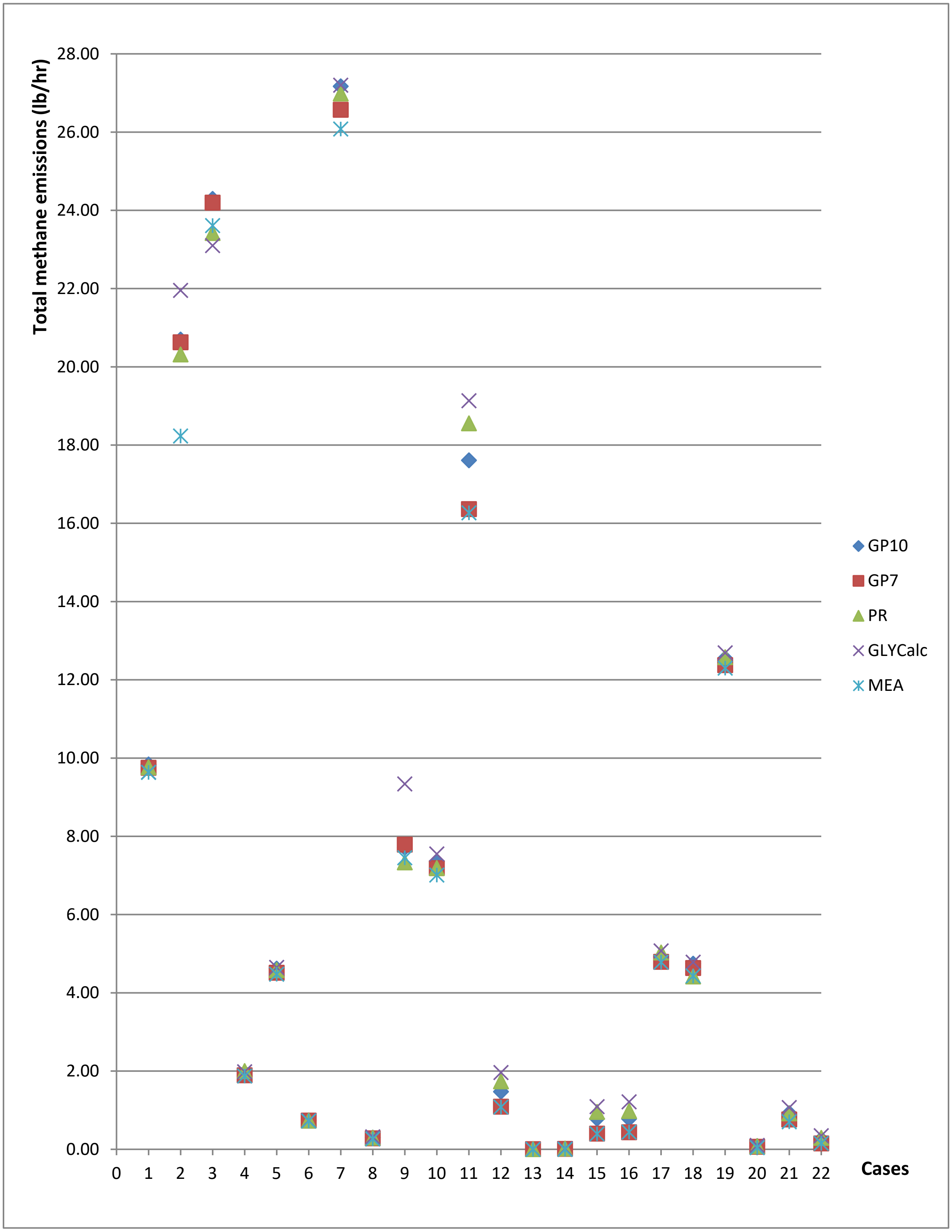

Figure 4 Total methane emissions estimate- TEG units

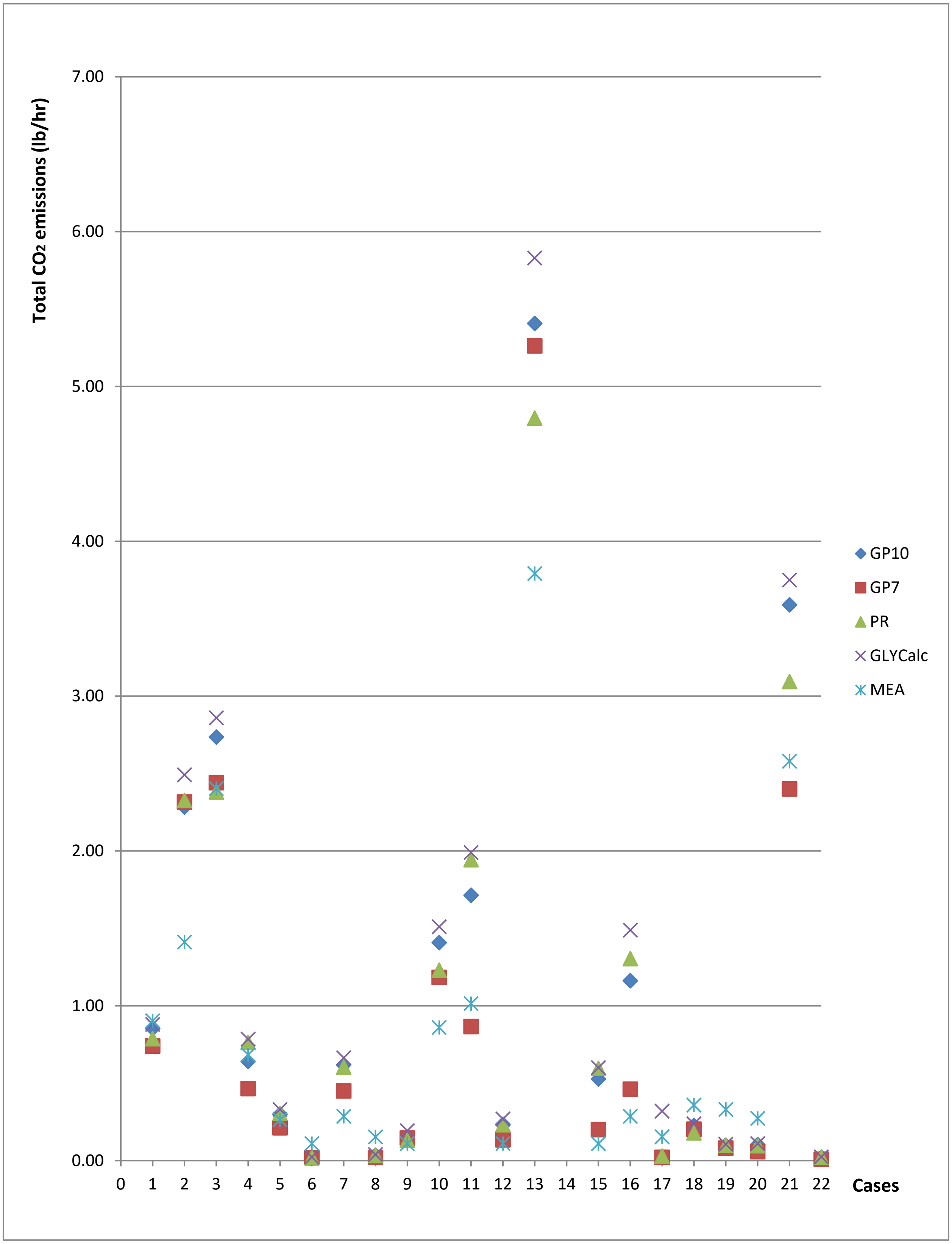

Figure 5 Total CO2 emissions estimate- TEG units

2.4.2. EG Refrigeration

In the next step, Ethylene Glycol (EG) refrigeration facilities were investigated. Operating data from 8 different EG facilities were collected and used in the comparison. The 8 facilities (shown in Table 4) are selected from among more than 160 EG facilities available in the Process Ecology Benzene Emissions Advisor database for different refrigeration process conditions. Almost all refrigeration units use electric pumps for glycol recirculation (only a few of them use gas pumps) and they don't use stripping gas in the glycol regeneration unit. Therefore, EG units are selected based on:

- Temperature and pressure of the Low Temperature Separator (LTS)
- Presence of a flash tank
- Type of pump used for glycol recirculation (gas pump or electric pump)

It is noted that no identifying information (client, facility, location) is used in the analysis, which identifies facilities only as "Case 1", "Case 2", etc.

Similar to TEG units, HYSYS and Glycalc simulation software as well as the correlation approach were used to estimate methane and CO_2 emissions from EG units. The default property package applied for simulating EG units in HYSYS is NRTL-PR property package with adjusted binary interaction parameters. The results of the analysis show that the HYSYS PR property package is not capable of predicting methane emissions accurately. Additionally, the GP in HYSYS V9-10 cannot predict an aqueous phase at LTS conditions for most cases (particularly for units with relatively low pressure in the LTS) and consequently is not able to accurately estimate methane and CO_2 emissions from EG units. Even if an aqueous phase is predicted by the simulator, the resulting emissions estimates are not close to emissions estimates by other approaches. Therefore, only four methods are used to estimate emissions from EG units as follows:

- ASPEN HYSYS V9-10 simulation- using NRTL-PR property package (NRTL-PR) with adjusted parameters[1]
- ASPEN HYSYS V7.0 simulation- using Glycol property package (GP7)
- GRI Glycalc software

Results of EG units emissions estimates (methane emissions in Table 17 and Figure 6, Figure 41-42, CO_2 emissions in Table 18 and Figure 7, Figure 43-44) show that the estimated overall methane emissions using these four different methods are very close in most cases. It should be noted that Glycalc sometimes fails to predict a liquid hydrocarbon phase in the LTS which can lead to incorrect emissions estimates in the facility. In almost all cases HYSYS V7.0 Glycol property package estimates the highest methane emissions among all methods.

The CO_2 emissions estimates from EG units are generally lower than methane emissions and the differences in CO_2 emissions estimates are not significant in most cases. Unlike methane emissions estimates, HYSYS V7.0 Glycol package corresponds to the lowest CO_2 emissions estimates in all cases. HYSYS V9-10 (NRTL-PR) provides the most consistent set of estimated values.

[1] When NRTL-PR is used hereafter in the report it refers to the NRTL-PR with adjusted parameters

Similar to TEG units, in case 1 with a flash tank, the difference in total methane and CO_2 emissions is observed in flash tank emissions.

Table 4 EG cases selected for emissions estimates comparison

Case	Pump type	Flash tank	LTS Temperature (°C)	LTS Pressure (kPag)
Case 1	Gas	Yes	-17	1450
Case 2	Gas	No	-23	2551
Case 3	Electric	Yes	0	690
Case 4	Electric	Yes	-24.7	4000
Case 5	Electric	Yes	-20	7500
Case 6	Electric	No	-24	1550
Case 7	Electric	No	-30	6300
Case 8	Electric	No	-29	4600

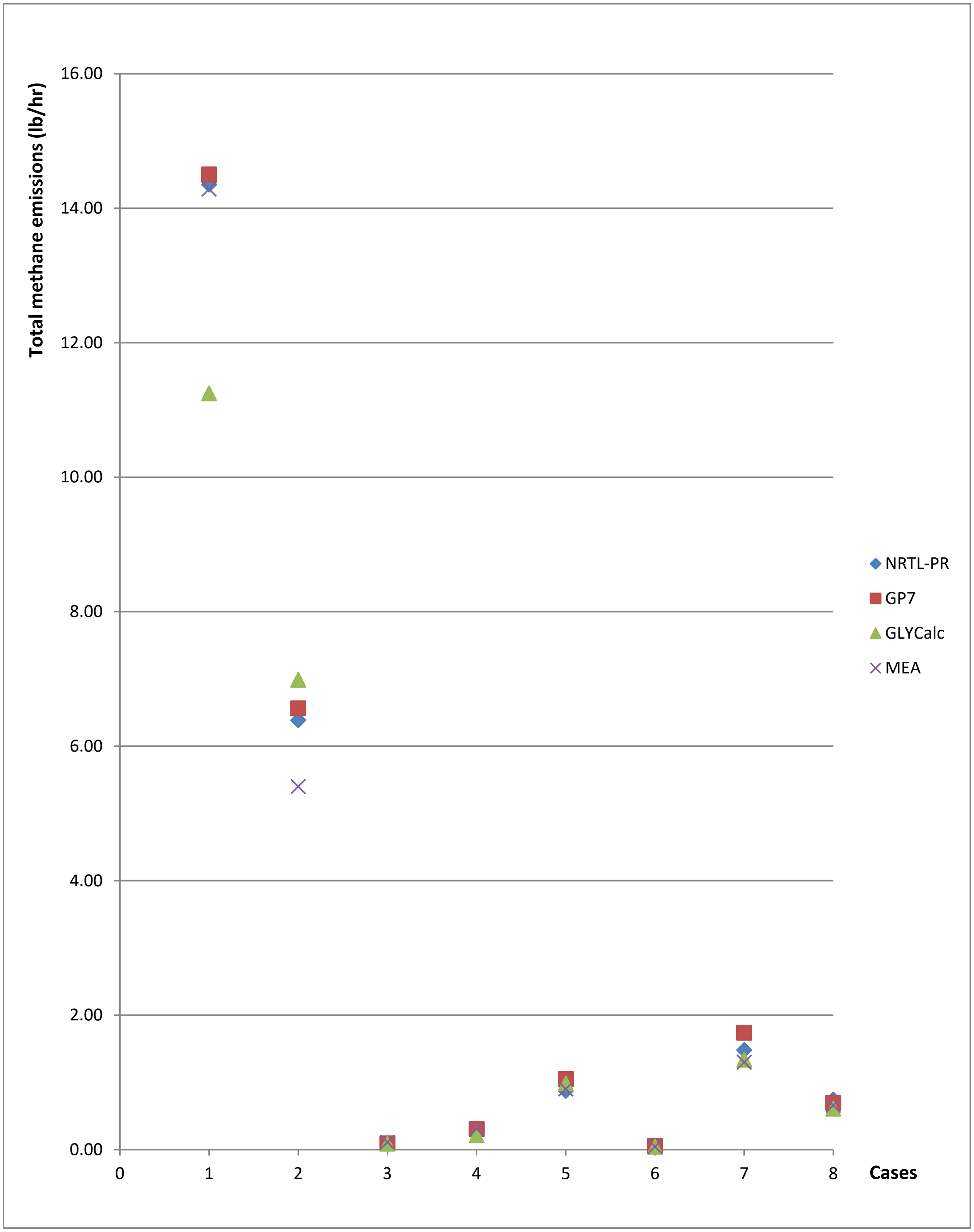

Figure 6 Total methane emissions estimate- EG units

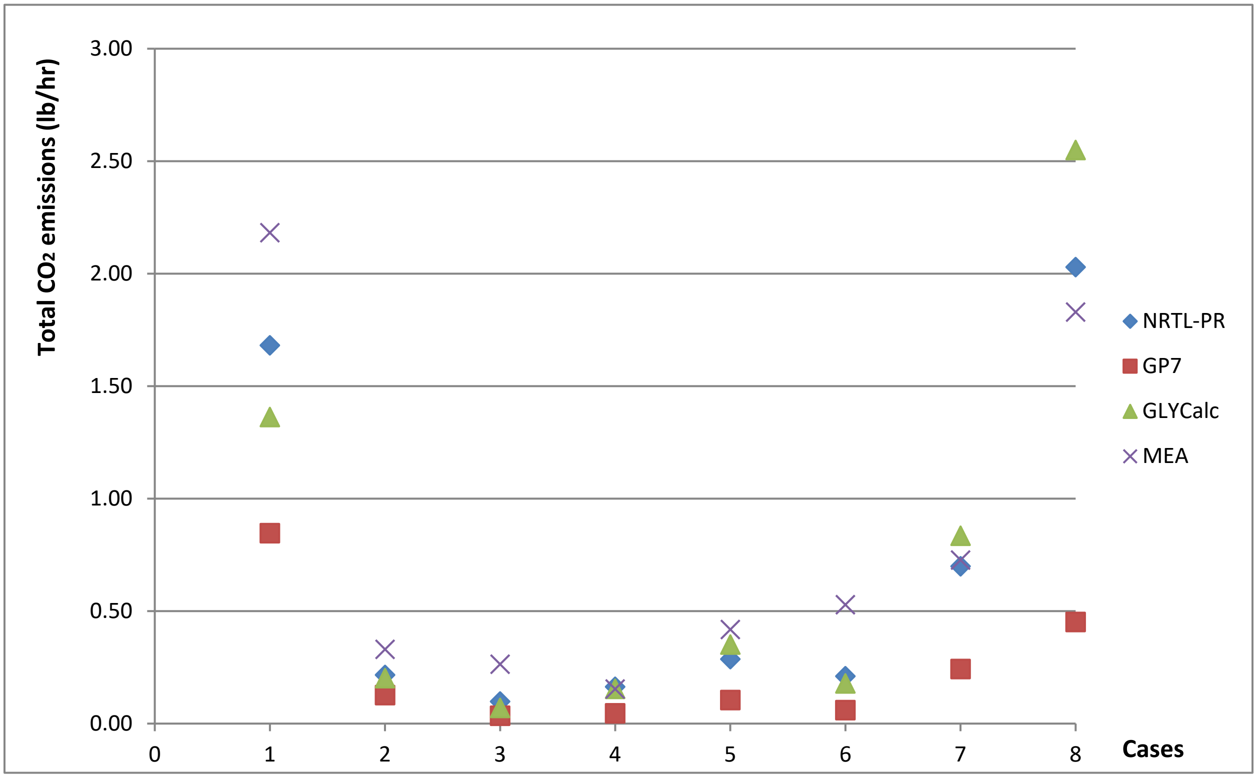

Figure 7 Total CO2 emissions estimate- EG units

2.5. Total Capture Test (TCT)

In this section we compare the simulation results for methane emissions in TEG and EG units with the results of total capture tests (TCT) performed on selected TEG and EG facilities. In the available TCT reports, methane emissions from the still are reported for several facilities. TCT reports are sorted based on the quality of the data provided in the report and 12 cases were selected for the comparison. Table 5 shows the information of the selected cases. It is worth noting that the cases used for the TCT comparison are different from the cases in Section 2 of this report as the TCT tests correspond to specific facilities and the simulation model was adjusted to represent the same configuration and operating conditions as the TCT.

All 12 cases are simulated in HYSYS V7.0, V10 and Glycalc and the results of simulation are compared to the results of TCT reports. It should be noted that in the HYSYS simulations, the cases are solved using the property packages with best performance as discussed earlier (i.e., GP7, GP9-10 for TEG units and NRTL-PR for EG units). The results of this comparison are shown in Figure 45 and Table 19.

In cases 1 and 2, methane emissions reported in the TCT reports are significantly higher than the results of all simulation methods. However, in all other cases where the methane emissions are lower, estimated emissions by simulation methods are close to TCT reported emissions. To see the results more clearly, Figure 8 show the results presented in Figure 45 but excludes cases 1 and 2 as outliers.

Table 19 shows the differences between TCT emissions and each of the emissions estimation methods for all 12 cases. As shown is this table, none of the estimation methods is consistently better than the others. However, in most cases **emissions estimated by all three methods are quite similar**.

Table 5 TCT cases information

Case	Type of facility	Pump type	Flash tank	Stripping gas	Contactor/LTS T (°C)	Contactor/LTS P (kPag)
Case 1	TEG	Gas	No	Yes	30	6000
Case 2	TEG	Gas	Yes	No	30	4730
Case 3	TEG	Electric	No	No	30	4688
Case 4	TEG	Gas	No	No	12	5600
Case 5	TEG	Gas	No	No	36	5200
Case 6	TEG	Gas	No	No	26	1570
Case 7	EG	Electric	Yes	No	-32	4700
Case 8	EG	Electric	Yes	No	-15	2500
Case 9	EG	Electric	Yes	No	-18	2706
Case 10	TEG	Electric	Yes	No	35	5790
Case 11	TEG	Electric	Yes	No	9	2600
Case 12	TEG	Electric	No	No	25	5200

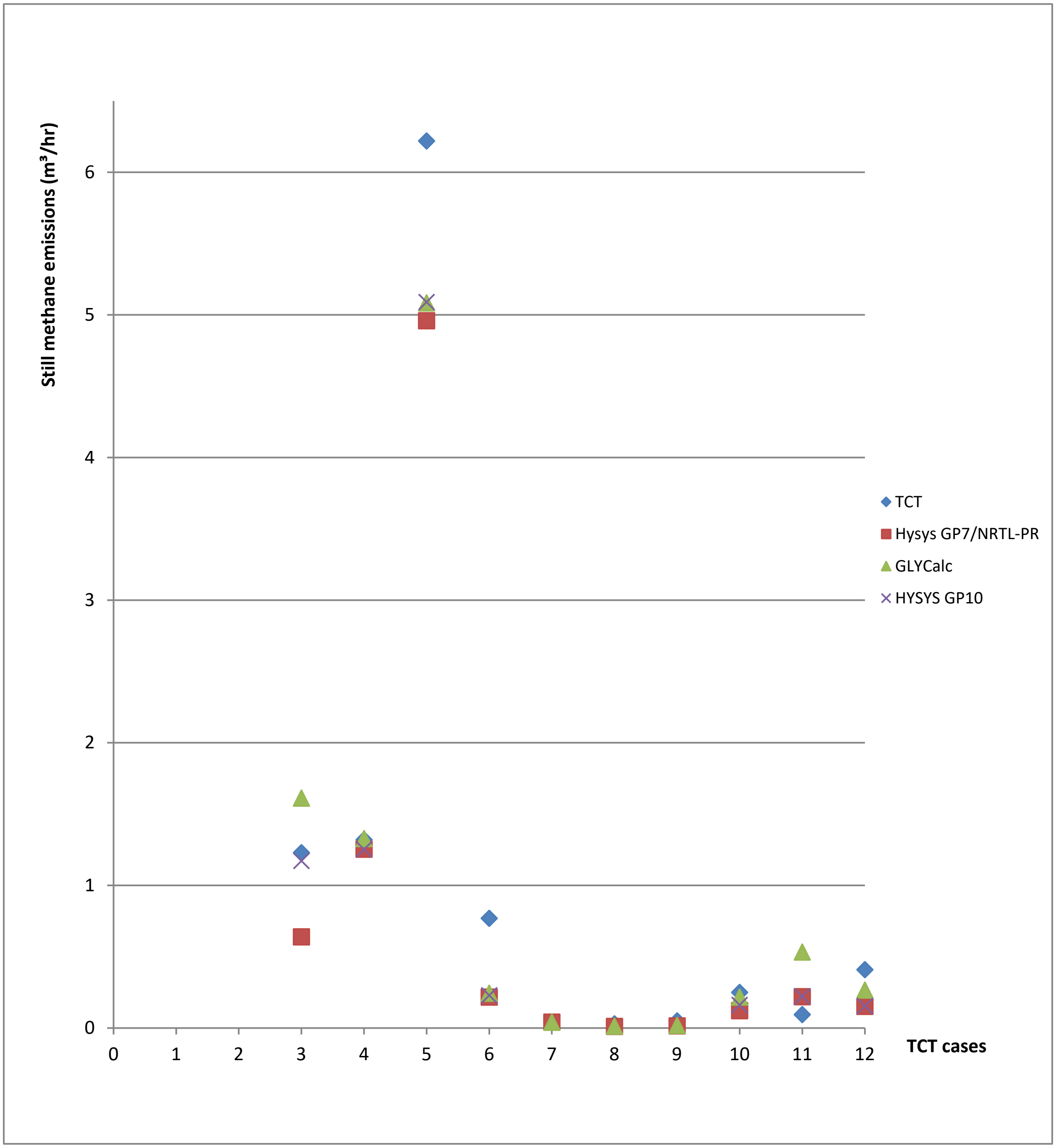

Figure 8 Still methane emissions comparison for TCT cases- excluding outliers (case 1 and case 2)

2.6. Conclusions

According to vapor-liquid equilibrium (VLE) data comparison, HYSYS V9-10 using the Glycol Property package is capable of predicting methane solubility in TEG with very high accuracy, with some deviations as the water content in the mixture increases. Comparing simulation results to the experimental data presented in GPA RR-131 shows that with **lower water content** in the mixture and at **lower pressures**, HYSYS Glycol package can predict the solubility of methane in the liquid phase of the wet gas and glycol mixture with high precision (less than 10% error). The results also show that the **Glycol package in HYSYS V9-10 (GP9-10) improves the methane solubility prediction compared to HYSYS V7.0 (GP7)** at all pressure and temperature conditions.

GRI Glycalc results are the closest fit to RR-131 data for methane equilibrium concentration in the wet gas and glycol mixture. However, the differences between Glycalc and HYSYS GP9-10 emissions estimates are marginal in most cases. Considering the flexibility and the additional process parameters that can be accessed in HYSYS, it may well be argued that GP9-10 is the preferred method for methane emissions estimation purposes.

The HYSYS simulation approach has some advantages over Glycalc such as better prediction of the dry gas water content, more flexibility to model alternative process configurations, and being able to test the estimation results under various conditions to compare to experimental data as reported in a previous study [5].

When comparing emissions estimates from dehydration facilities, we conclude that in most cases there are no significant differences between the estimated emissions using different methods. According to the results of emissions comparison, both HYSYS and the correlation methods show promising results for methane and CO_2 emissions. The **correlation method estimates of methane emissions match HYSYS GP7 results with reasonable accuracy (less than 5% error) in 90% of cases**. The advantage of using the correlation method is that is a much simpler and efficient approach.

For refrigeration facilities, the adjusted NRTL-PR property package seems to be the most reliable method as it can predict two distinctive liquid phases at low temperature separator (LTS) under various conditions. **Both Glycalc and HYSYS GP9-10 are not able to consistently predict both aqueous and liquid hydrocarbon phases at LTS conditions which results in inaccurate emissions estimates**. Methane emissions estimates obtained by the correlation method are close to HYSYS NRTL-PR in all but one case.

Comparing simulation results to total capture test (TCT) emissions is not conclusive. In case 1 and case 2, TCT emissions are significantly higher that the results of all simulation methods. This could be due to measurement errors at the facility. In most of the remaining 10 cases, simulation methods have similar emissions estimates and consequently, similar errors compared to TCT results. As additional TCT reports with reliable results are available, we can expand the comparison to a larger number of cases and reach better conclusions.

Although the differences in methane emissions between HYSYS GP9 and HYSYS GP10 are not significant, it was determined that the prediction of aromatic compounds (BTEX) had better performance in HYSYS GP9.

Taking all these factors into account, **HYSYS GP9 and HYSYS NRTL-PR were determined to be the best calculation methods and are used in the remainder of this report for all TEG dehydration and EG Refrigeration cases respectively.**

3. Sensitivity Analysis: key process variables that affect methane emissions in dehydration / refrigeration facilities

3.1. Overview

Sensitivity analysis is a convenient approach to identify the main process model variables which contribute most to the variation in the model response. The analysis involves perturbing each individual model parameter to determine the effect of the change on the response of the model.

Conducting sensitivity analysis in glycol dehydration and refrigeration process models provides guidance for engineers and operators to quantitatively assess the consequences of changing a given parameter before committing significant investment or making changes to the operating conditions. In addition, it allows for simplification of the model for further investigation and future studies by eliminating insignificant parameters.

There are two types of sensitivity analysis: local and global sensitivity analyses. The former examines the changes in model output by varying inputs one at a time by a small amount around some fixed point while the values of other parameters are kept fixed. Examples of local analysis include the differential analysis method [6], [7], one-at-a-time method [6], [8], Factorial design [9], and Importance Factor [8]. Global sensitivity evaluates the model response by varying all inputs simultaneously over their entire range of variation by taking into consideration the correlations between inputs such as importance index, the relative deviation method, the relative deviation ratio, Pearson's r, the partial correlation coefficients, and regression techniques (standardized and ranked) [6]. The one-at-a-time method (local sensitivity analysis) is used in this work since it is widely used and easy to interpret.

3.2. TEG Dehydration Systems

A sensitivity analysis of the key operating variables on total methane emissions was performed considering a sample of eight TEG dehydration units representing typical configurations found in the Canadian UOG sector. The differences between these cases include the type of glycol pump in use (gas vs. electric), the presence/absence of a rich glycol flash tank, and the use of stripping gas vs. no stripping gas in the regeneration column.

Table 6 Summary of cases tested for TEG dehydration system

Case	Case Details
Case 1	Gas pump, Flash tank, Stripping gas
Case 2	Gas pump, Flash tank, No stripping gas
Case 3	Gas pump, No flash tank, Stripping gas
Case 4	Gas pump, No flash tank, No stripping gas
Case 5	Electric pump, Flash tank, Stripping gas
Case 6	Electric pump, Flash tank, No stripping gas
Case 7	Electric pump, No flash tank, Stripping gas
Case 8	Electric pump, No flash tank, No stripping gas

In this case, "gas pump" refers to the Kimray energy exchange pump commonly used in dehydration facilities.

Based on a sample of over 400 operating TEG dehydration plants in Western Canada, average values for the key parameters were determined and a base case was established. This approach included averaging inlet gas composition as well.

For each simulation run in the sensitivity analysis, these average parameters were varied by +/- 50% around the base case value. The average parameters and their explored ranges are summarized in Table 7.

It is noted that for this analysis, all parameters were varied by the same percent amount. It is important to clarify that "typical" variance of these variables is not the same, in practice. In addition, while some of these parameters can be controlled, others cannot. Therefore, further explanation is required in order to identify which parameters provide some measure of control of methane emissions in practice, which this section clarifies.

Table 7 Process Parameters for Sensitivity Analysis

Uncertain Parameters	Unit	Base Case	Min	Max
Gas Flowrate	e3m3/d	300	150	450
Contactor Temperature	C	27	13.5	40.5
Contactor Pressure	kPag	5500	2750	8250
Circulation Rate	gpm	1.6	0.8	2.4
Flash Tank Temperature	C	45	22.5	67.5
Flash Tank Pressure	kPag	400	200	600
Stripping Gas Rate	scfm	4.8	2.4	7.2
Reboiler Temperature	C	194	172	204

For **Case 1** (refer to Table 6) where the dehydration facility includes 1) a Kimray glycol pump, 2) a flash tank and 3) where stripping gas is in use, the results are displayed as a tornado chart in Figure 9. As can be observed in the chart, the most sensitive variables, in descending order, are the contactor pressure, glycol circulation rate and stripping gas rate.

The contactor temperature does have some influence on the amount of methane that is absorbed by the glycol and thus on the methane emissions rate, but it is not as significant as other parameters. However, it should be noted that the range of temperature studied here is typical of dehydrators which are downstream of compressors. In this case, the performance of the compressor after coolers can vary significantly throughout the year depending on ambient conditions, and therefore methane emissions can be expected to vary throughout the year, depending on the temperature of the gas to the dehydrator. On the other hand, contactor pressure is not expected to vary significantly, nor does the operator typically have the ability to control this parameter.

It is interesting to point out that the gas rate to the dehydrator has minimal influence on methane emissions (while holding other parameters constant, including glycol circulation rate). This result, although slightly counterintuitive, would advise against the ranking of methane emissions mitigation actions based on facility size only. While one would expect glycol circulation rate (a much more important parameter impacting methane emissions) to increase with gas rate, it is well known that facilities operate with a wide range of glycol to gas ratios. This is one reason why emissions factors based on gas rate alone would be useful only for aggregate emissions estimates.

Methane emissions are very sensitive to glycol circulation rate and stripping gas rate. These parameters can generally be controlled, and it is a good strategy to ensure that the glycol circulation rate and use of stripping gas is enough to ensure the gas is adequately dried, while not overcirculating glycol or unnecessarily employing stripping gas.

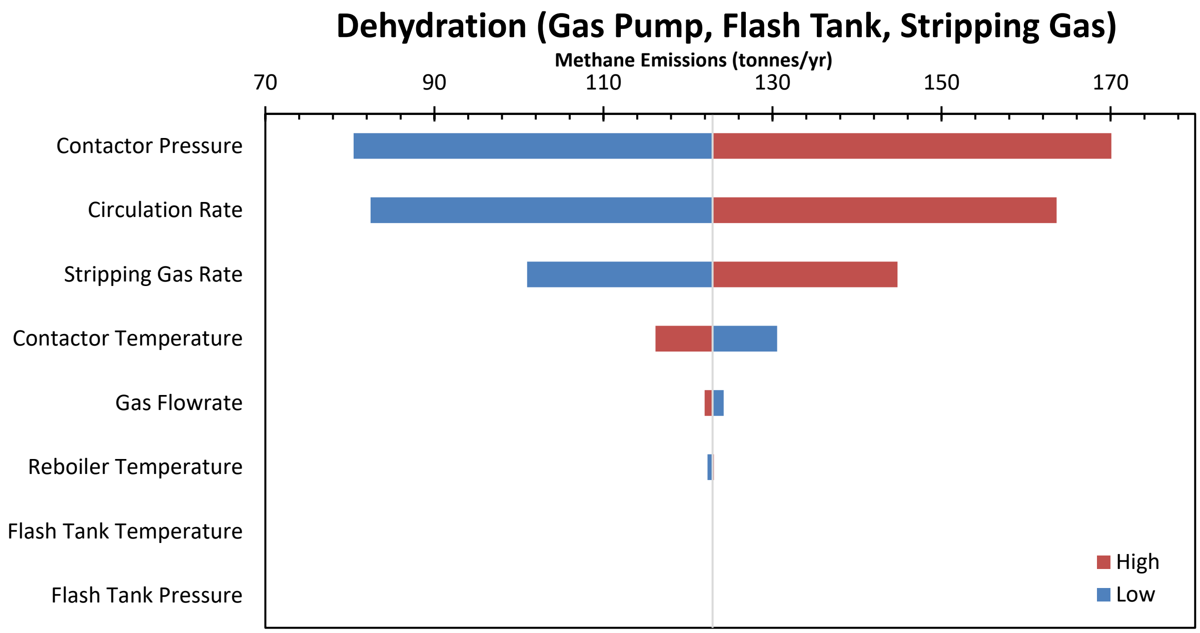

Figure 9 Sample Sensitivity Analysis of TEG Case with a gas glycol pump, a rich glycol flash tank and stripping gas

Figure 10 shows the sensitivity analysis for a TEG dehydration unit with 1) an electric pump, 2) no flash tank, and 3) no stripping gas (See **Case 8** in Table 6). In this case, the variability in methane emissions is solely a result of methane solubility in the glycol. The most sensitive parameter becomes circulation rate, followed by contactor pressure. When these parameters are varied by +/- 50%, the methane emissions are in the range 2-9 tonnes/yr, a very small magnitude compared to the methane emissions shown in Figure 9.

In contrast to **Case 1** (gas pump and use of stripping gas), the effects of contactor temperature, gas flow rate, and reboiler temperature present similar magnitude to the others (on the order of 1-2 tonnes/yr).

These results suggest that circulation rate and reboiler temperature are parameters that should be optimized in all cases to reduce methane emissions for TEG dehydration units.

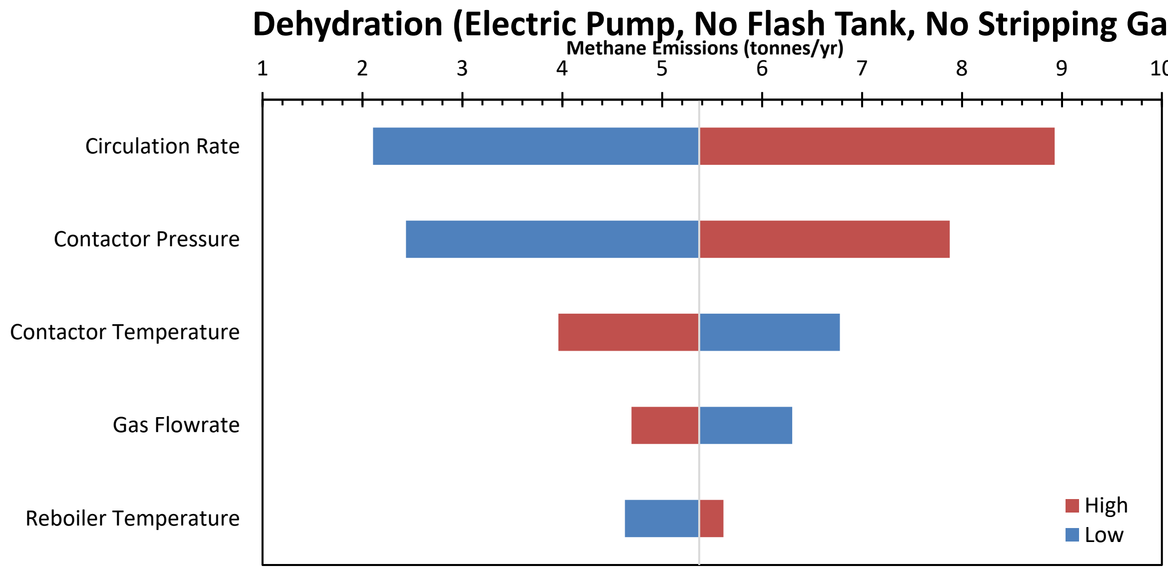

Figure 10 Sample Sensitivity Analysis of TEG Case with an electric glycol pump, no flash tank or stripping gas

For conciseness, detailed results for all the cases are not shown in this section of the report (refer to 8. Appendix A: Figures and Tables). Instead, a summary of the cases and key conclusions is summarized as follows:

Table 8 Summary of cases tested for TEG dehydration system

Case	Case Details	Methane Emissions Range (tonnes/yr)	Comments
Case 1	Gas pump, Flash tank, Stripping gas	81-170	Stripping gas and circulation rate are key parameters
Case 2	Gas pump, Flash tank, No stripping gas	37-125	Circulation rate is key parameter; contactor conditions also have significant impact on methane emissions
Case 3	Gas pump, No flash tank, Stripping gas	81-170	Stripping gas and circulation rate are key parameters
Case 4	Gas pump, No flash tank, No stripping gas	37-125	Circulation rate is key parameter; contactor conditions also have significant impact on methane emissions
Case 5	Electric pump, Flash tank, Stripping gas	28-71	Impact of stripping gas most significant
Case 6	Electric pump, Flash tank, No stripping gas	2-9	Impact of circulation rate, contactor conditions, and reboiler temperature are important, but emissions are low
Case 7	Electric pump, No flash tank, Stripping gas	28-71	Impact of stripping gas most significant

Case 8	Electric pump, No flash tank, No stripping gas	2-9	Impact of circulation rate, contactor conditions, and reboiler temperature are important, but emissions are low

It is noted that the results for cases with the same pump type and stripping gas options are the same, regardless of the existence of a flash tank. This is because nearly all methane would be vented either from the flash tank (if present) and/or the still overhead. However, if the flash tank had a different control than the still overhead, then the results could be significantly different. For example, if the flash tank overhead is vented, and the still overhead is routed to flare, then the presence of a flash tank would in this case significantly increase methane emissions, since methane would be allowed to vent at the flash tank.

The key conclusions are as follows:

1. Glycol circulation rate should be optimized, particularly in cases where there is a Kimray pump.
2. Methane emissions can be significantly reduced by turning off stripping gas (or using it only when required).
3. Reboiler temperature should be set close to 200 C. If the reboiler temperature were significantly lower, a higher circulation rate may be required to ensure adequate drying of the gas, which would result in higher methane emissions.
4. Contactor conditions can have a significant effect on methane emissions; however, these conditions can rarely be controlled. The gas temperature to the contactor could vary throughout the year, particularly if there is upstream compression. Assuming a constant glycol circulation rate for the year, methane emissions would be highest in the winter when the contactor operates at lower temperatures and benzene absorption to the glycol increases.
5. Strategies for methane reduction can depend on what controls are in place for the flash tank vs. the still overhead.
6. If there is an electric pump and no stripping gas is used, methane emissions will already be very low and further optimization would typically not yield significant methane reductions.

3.3. EG Refrigeration Systems

A sensitivity analysis of the key operating variables on total methane emissions was performed considering a sample of four ethylene glycol (EG) refrigeration units representing typical configurations found in the Canadian UOG sector. The differences between these cases include the type of glycol pump in use (gas vs. electric) and the presence/absence of a flash tank in the rich glycol stream.

Table 9 Summary of cases tested for EG refrigeration system

Case	Case Details
Case 1	Gas pump, Flash tank
Case 2	Gas pump, No Flash tank
Case 3	Electric pump, Flash tank
Case 4	Electric pump, No flash tank

As mentioned before, "gas pump" refers to the Kimray energy exchange pump often used in glycol regeneration facilities.

In the case of a unit where a Kimray glycol pump is used (**Case 1**, Figure 11), LTS pressure and glycol circulation rate are by far the most sensitive parameters. Since the low temperature separator (LTS) pressure would typically not be controlled, the glycol circulation rate is the only significant means available to reduce methane emissions.

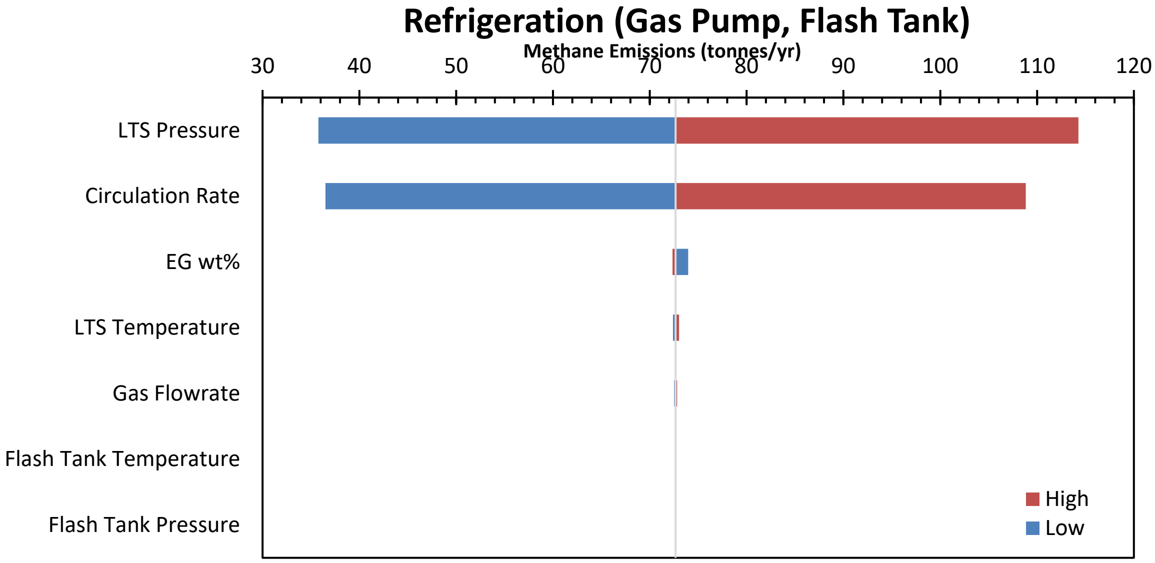

Figure 11 Sample Sensitivity Analysis of EG case with a gas pump and flash tank

When there is no gas pump or rich glycol flash tank (**Case 2**, Figure 12), the most sensitive parameters are similar in magnitude. However, the magnitude of methane emissions is very low, suggesting little opportunity for optimization to achieve methane emissions reduction.

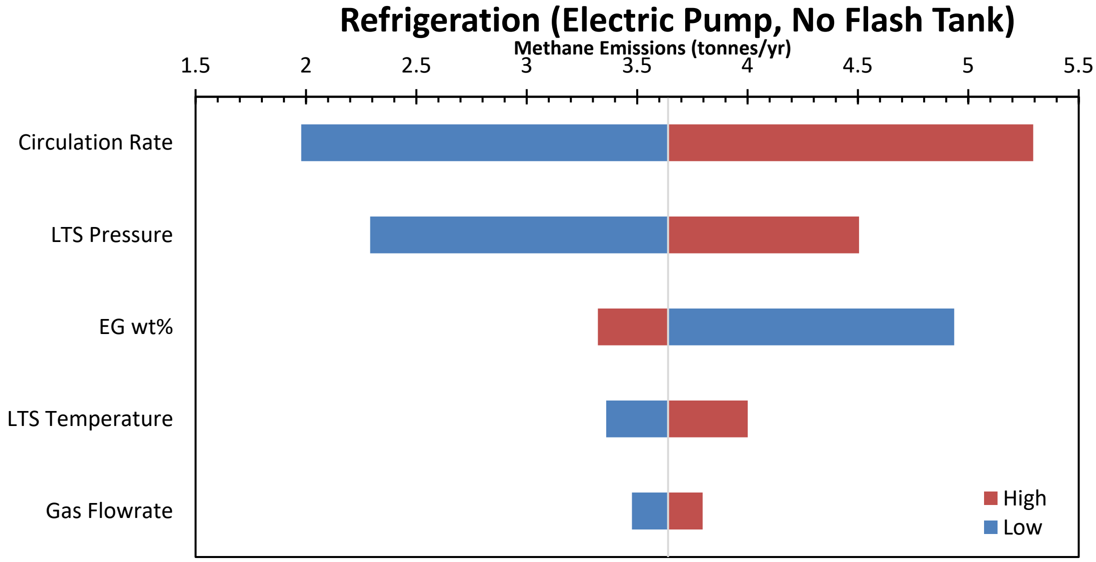

Figure 12 Sample Sensitivity Analysis of EG case with an electric pump and no flash tank

For conciseness, detailed results for all the cases are not shown in this report (refer to 9. Appendix A: Figures and Tables). Instead, a summary of the cases and key conclusions is summarized as follows:

Table 10 Summary of cases tested for TEG dehydration system

Case	Case Details	Methane Emissions Range (tonnes/yr)	Comments
Case 1	Gas pump, Flash tank	36-114	Circulation rate is the key parameter for methane emissions reduction
Case 2	Gas pump, No Flash tank	36-114	Circulation rate is the key parameter for methane emissions reduction
Case 3	Electric pump, Flash tank	2-5	Methane emissions are very low
Case 4	Electric pump, No flash tank	2-5	Methane emissions are very low

As previously mentioned, the results for cases with the same pump type are the same, regardless of the existence of a flash tank. This is because nearly all methane would be vented either from the flash tank (if present) and/or the still overhead. However, if the flash tank had a different control than the still overhead, then the results could be significantly different.

The key conclusions are as follows:

1. Glycol circulation rate should be optimized, particularly in cases where there is a Kimray pump.
2. LTS conditions can have a significant effect on methane emissions, but these conditions can rarely be controlled.
3. Strategies for methane reduction can depend on what controls are in place for the flash tank vs. the still overhead.
4. If there is an electric pump in use, then methane emissions will already be very low and further optimization would typically not yield significant methane reductions.
5. In general, refrigeration glycol regeneration facilities offer less opportunity for methane reductions than dehydration facilities, largely due to the fact that stripping gas is not used, and electric pumps are more likely to be employed in refrigeration facilities.

3.4. Assessment of Individual Parameters

This section provides a summary of the key parameters which influence methane emissions from TEG dehydration units.

Glycol Circulation Rate

Glycol circulation rates must be high enough to achieve the sales gas water content specification (TEG dehydration) or ensure hydrate formation suppression (EG refrigeration). However, many facilities over-circulate glycol, resulting in unnecessary costs and emissions. Also, for cases where a Kimray pump is used, overcirculation results in even higher methane emissions, as more gas is required to pump the additional glycol. Figure 13 shows the effect of glycol circulation rate on methane emissions for a TEG unit with a gas vs. electric glycol pump. Methane emissions increase approximately linearly with glycol circulation rate, with a much greater increase in methane emissions for the Kimray pump for the same increase in circulation rate.

Optimization of circulation rate represents one of the most significant opportunities for methane reductions in dehydration and refrigeration facilities.

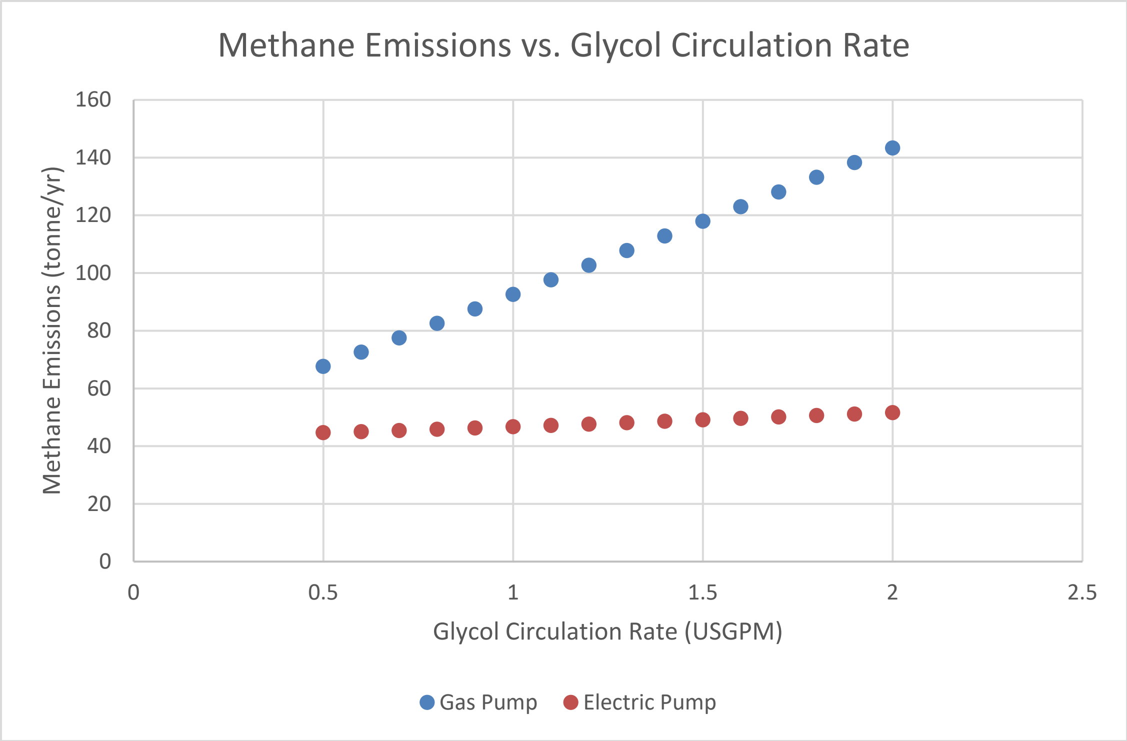

Figure 13 Methane Emissions vs. Glycol Circulation Rate for Gas Pump (Case 1) and Electric Pump (Case 5)

Stripping Gas

Stripping gas is sometimes used at dehydration facilities to improve glycol regeneration which may be required to meet dry gas specifications on warm summer days when the inlet gas temperature may be higher. As stripping gas is increased, the glycol purity begins to plateau while methane emissions continue to increase, as seen in Figure 14 - Figure 15. Usually, the use of 2-3 SCF stripping gas per gallon of glycol circulated is sufficient, when stripping gas is required.

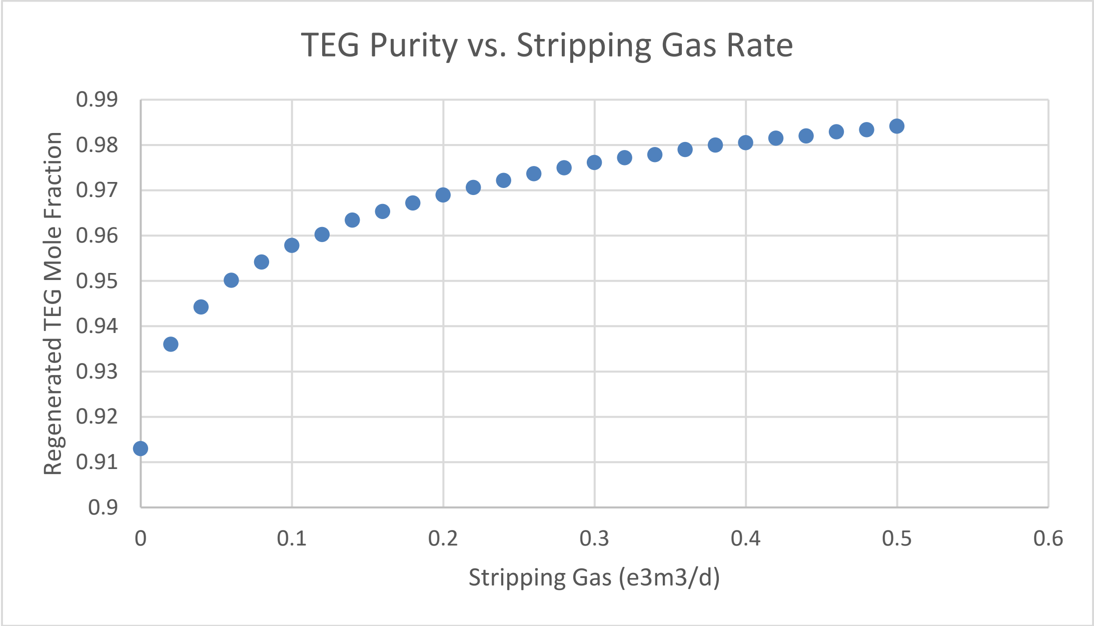

Figure 14 TEG Purity vs. Stripping Gas (Case 1)

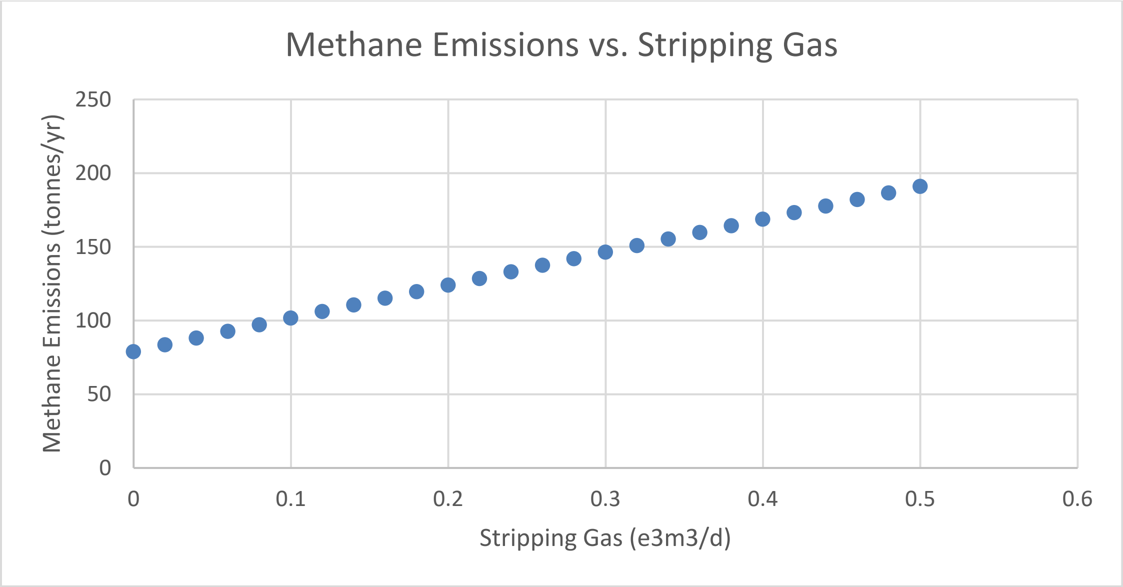

Figure 15 Methane Emissions vs. Stripping Gas Rate (Case 1)

Stripping gas is most likely necessary in the warmer summer months when the gas temperature to the contactor is highest. In winter months, and in some cases year-round, it may be possible to reduce or eliminate stripping gas use without any compromise to operational reliability, which would be a good way to reduce methane emissions.

Reboiler Temperature

For dehydration units, reboiler temperature should be set close to 200 C. If the temperature were significantly lower, the ability of the reboiler to regenerate the glycol would be compromised, potentially requiring a higher glycol circulation rate or the use of stripping gas in order to ensure the gas is adequately dried. Either of these measures would unnecessarily increase methane emissions.

It is further noted that higher temperatures (above 205 C), could result in degradation of the TEG, which could also ultimately require higher glycol circulation rate or use of stripping gas in order to ensure adequate gas dehydration.

Flash Tank

The flash tank conditions (pressure and temperature) have minimal impact on methane emissions.

The controls used for the flash tank overhead vs. the still overhead should be evaluated when making decisions to reduce methane emissions. For example:

- If the flash tank overheads were (e.g.) vented, and still overhead flared, glycol pump rate reductions would likely result in higher methane reductions, than stripping gas reductions.
- If the flash tank overheads were (e.g.) flared, and still overhead vented, stripping gas reductions would likely result in higher methane reductions, than glycol pump rate reductions.
- Installation of a flash tank to remove non-condensables can result in improved performance of still vent condenser tanks and thus, lower benzene emissions. However, this will have no impact on methane emissions (methane is non-condensable).

Contactor Pressure and Temperature

Contactors running at lower pressure result in significantly lower methane emissions. Figure 16 shows the impact of methane emissions on contactor pressure (for **Case 1**).

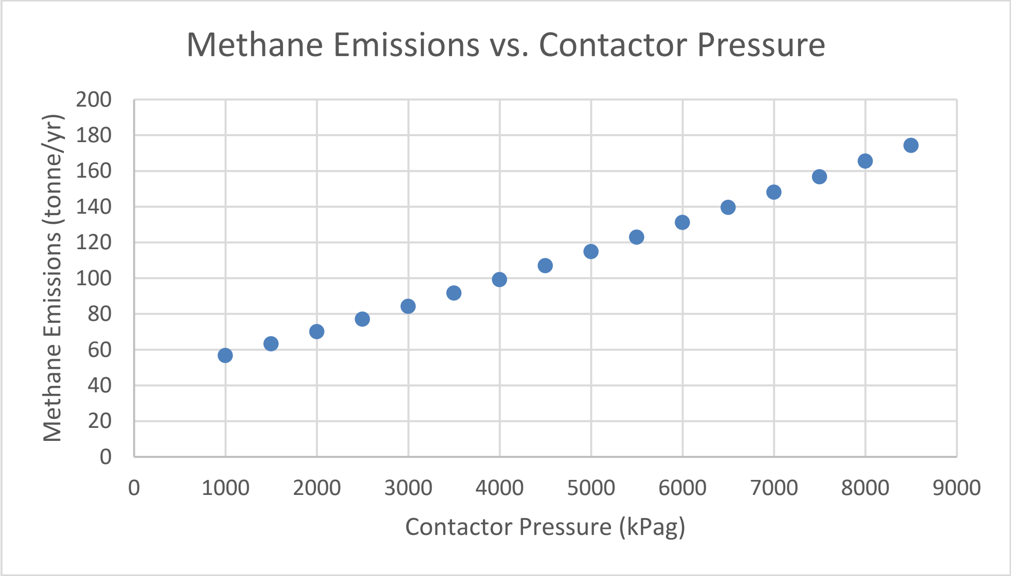

Figure 16 Methane Emissions vs. Contactor Pressure (Case 1)

Table 11 shows the methane emissions for the cases where contactor pressure is 5500 kPa and 1200 kPa. Percent reductions are most significant when stripping gas is not used.

Table 11 Total methane emissions for varying contactor pressure

Case	Case Details	5500 kPag Total Methane (t/yr)	1200 kPag Total Methane (t/yr)	% Reduction with LP Contactor
Case 1	Gas pump, Flash tank, Stripping gas	122.94	59.29	52%
Case 2	Gas pump, Flash tank, No stripping gas	78.76	15.87	80%
Case 3	Gas pump, No flash tank, Stripping gas	122.93	59.29	52%
Case 4	Gas pump, No flash tank, No stripping gas	78.76	15.87	80%
Case 5	Electric pump, Flash tank, Stripping gas	49.55	44.26	11%
Case 6	Electric pump, Flash tank, No stripping gas	5.36	0.85	84%
Case 7	Electric pump, No flash tank, Stripping gas	49.54	44.26	11%
Case 8	Electric pump, No flash tank, No stripping gas	5.11	0.85	83%

A sensitivity analysis was performed for the low pressure (1200 kPag) contactor, with all parameters varied by +/-50% from the default values, as before.

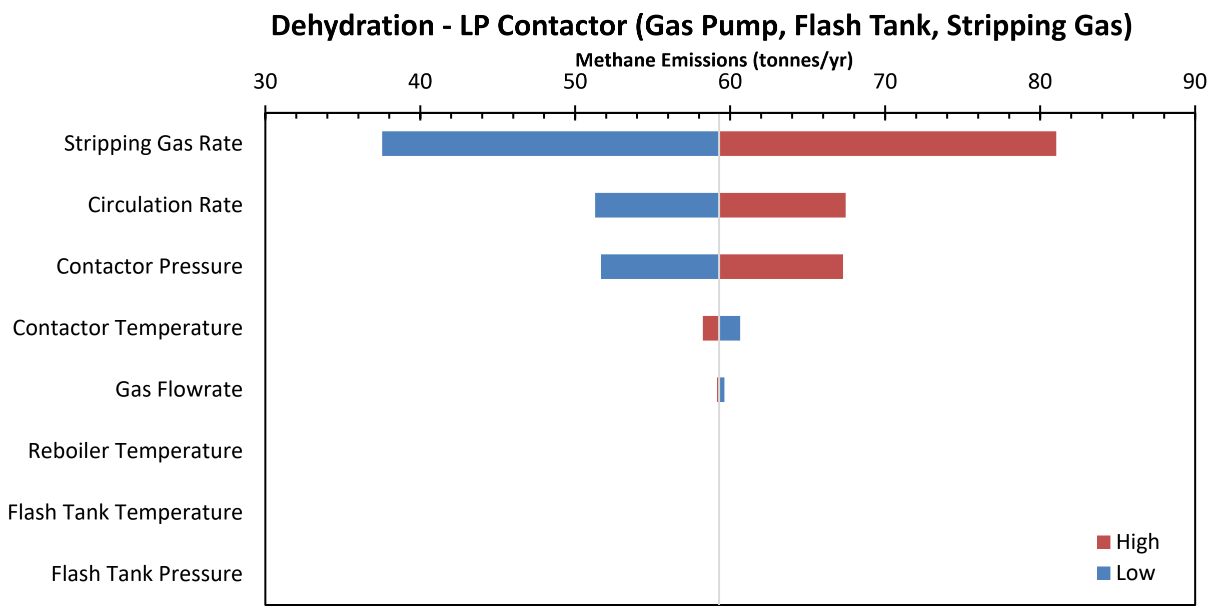

Figure 17 Sensitivity Analysis for Case 1 with LP Contactor

Figure 17 shows that at lower contactor pressures, the use of stripping gas has a much greater impact than before, since other parameters are less important due to reduced methane absorption in the glycol at lower contactor pressures.

Gas Composition

If the inlet gas has a higher fraction of methane, more methane will be emitted in the process. Lean gas is described as gas with a higher methane fraction, while rich gas is described as gas with lower methane fraction and a higher fraction of heavier hydrocarbons (propane, butane, etc.). Case 1 (refer to Table 8) was evaluated for three inlet gas compositions. These results are reported in Table 12, which shows a proportional increase in methane emissions as the inlet methane composition increases.

Table 12 Effect of gas composition on emissions

Gas Type	Methane Mole Fraction	Total Methane Emissions (t/yr)
Average Gas	0.8975	122.94
Lean Gas	0.9865	131.70
Rich Gas	0.7300	107.07

4. Technologies for Methane Reduction

There are several options available to gas processing operators to reduce methane emissions from glycol dehydration facilities. Some methods involve changing operating conditions and do not incur any capital expenditures. Others require the installation of new pieces of equipment. In this section, the most widely used methods are described, along with estimates for their methane reduction potential and associated marginal abatement cost. For a detailed description of each of these technologies, see Appendix A.

A number of studies have been recently published that consider the abatement cost of various technology options to reduce methane emissions in the oil & gas sector [9, 15, 33, 34, 35, 36]. In general, these studies indicate that achieving the 45% reductions required by both Provincial and Federal Government in Canada is feasible with marginal costs that are no higher than $11.02 CAD/tCO2e [33]. This report expands on the specific characteristics of the options available for glycol dehydration facilities.

The various technology options evaluated in this report have been organized as follows:

- Process Optimization: Review and optimization of operating conditions with no capital expenditures involved.
- Process Modifications: Review and optimization of operating conditions with capital costs involved to change the configuration of the dehydration process.
- Thermal combustion: Technology added as end-of-pipe emissions control resulting in the oxidation of methane.
- Vapor recovery/ combustion: technology added as end-of-pipe emissions control with beneficial use of the recovered gas.

In order to determine the marginal abatement cost of each one of the reviewed options, a typical TEG dehydration facility was defined based on average conditions from a sample of over 400 operating facilities in Western Canada. The methane emissions from this base case are assumed to be typical across industry.

The base case was implemented as a simulation model (Aspen HYSYS v 9.0) using the Glycol Property Package as indicated in Section 1 of this report, and the various technologies were simulated in the model to determine the methane emissions reductions that would result from their implementation. Cost estimates are average values based on a combination of publicly available reports [9, 15, 18, 26, 34] as well as information provided by technology suppliers, service companies, and oil and gas companies. Details of the assumptions used in the economic evaluation are presented in Section 5. It is acknowledged that the actual installed cost of the various technology options would vary depending on multiple factors such as facility size, location, layout, regulatory constraints, and supplier among others.

1.1 TEG Dehydration Base Case

Based on a sample of TEG dehydration plants in Western Canada, average values for key operating parameters were determined. This approach included the use of an averaged inlet gas composition as well and is included in 10. Appendix B: Average Gas Composition. Table 13 describes the operating parameters average values for the base case facility.

Table 13- Average operating parameters for base case

Operating Parameters	Unit	Base Case
Gas Flowrate	e3m3/d	300
Contactor Temperature	C	27
Contactor Pressure	kPag	5500
Circulation Rate	gpm	1.6
Stripping Gas Rate	scfm	4.8
Reboiler Temperature	C	194

The base case facility is also assumed to operate using a gas-driven (Kimray) pump and does not include a flash tank. The general configuration of a typical TEG dehydration plant is illustrated in Figure 18.

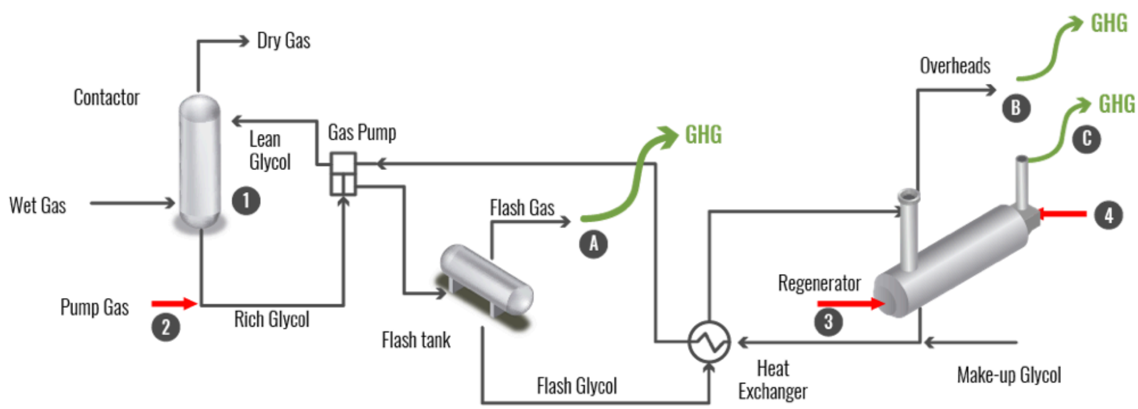

Figure 18- Typical configuration for a TEG dehydration plant

Although greenhouse gas emissions arise also from combustion (CO2), the methane emission sources from dehydration plants are the process vents from the flash tank (A) and the still overhead (B). In the base case, all of the methane venting takes place from the still overhead.

1.2 Process Optimization

Before considering the installation of new technologies, operators must consider options to optimize operating conditions at glycol dehydration facilities. The impact of operating parameters on methane emissions was reviewed in detail in Section 2 of this report, and there are several publications which discuss emissions and energy efficiency in TEG dehydration plants; some examples can be found in the references [10, 16, 17, 35, 36]. These facilities offer opportunities for optimization related to the glycol circulation rate and the use of stripping gas as described in the following sections.

Circulation Rate Reduction

Glycol circulation rate reduction has been recognized as one of the simplest and most effective approaches in reducing energy and emissions from dehydration and refrigeration facilities.

At low to moderate glycol circulation rates, water removal is directly proportional to glycol circulation rate. However, beyond a certain point, the gas water content can no longer be further decreased with increased glycol circulation as illustrated in Figure 19 which shows a typical chart of dry gas water content as a function of glycol circulation rate as well as associated benzene emissions. These charts are required to be posted at all glycol dehydration facilities in Western Canada as defined in various regulations (AER Directive 039, Letter #OGC 07-03, SK S-18).

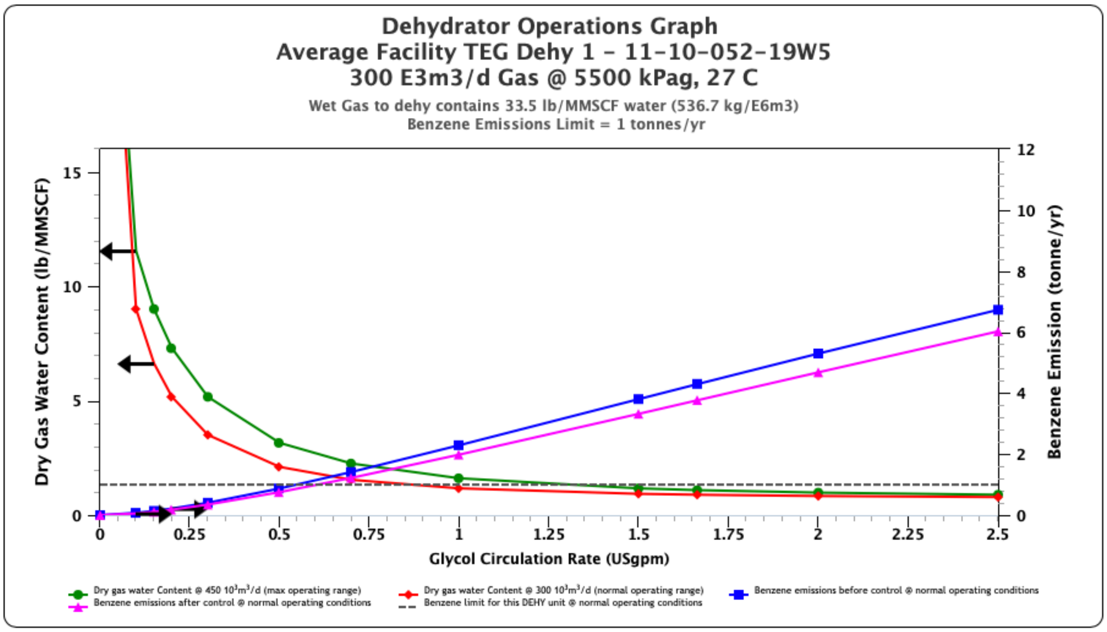

Figure 19 Dry gas water content and emissions with varying circulation rate

In order to determine the opportunity for glycol circulation rate reductions and consequent reductions in methane emissions, a set of heuristic rules can be applied to each particular case. The range of adequate glycol circulation to achieve standard dry gas water content has been reported as 2-4 gal TEG per lb of water removed from the wet gas [7, 13, 25]. In this evaluation, a conservative approach has been assumed using 4 gal TEG/ lb of water removed to determine the “optimal” circulation rate. The following figure shows the performance of the base case unit in terms of energy and fuel gas consumption and it can be observed that for the base case it is possible to reduce the circulation rate from the current 1.6 USGPM to approximately 0.8 USGPM.

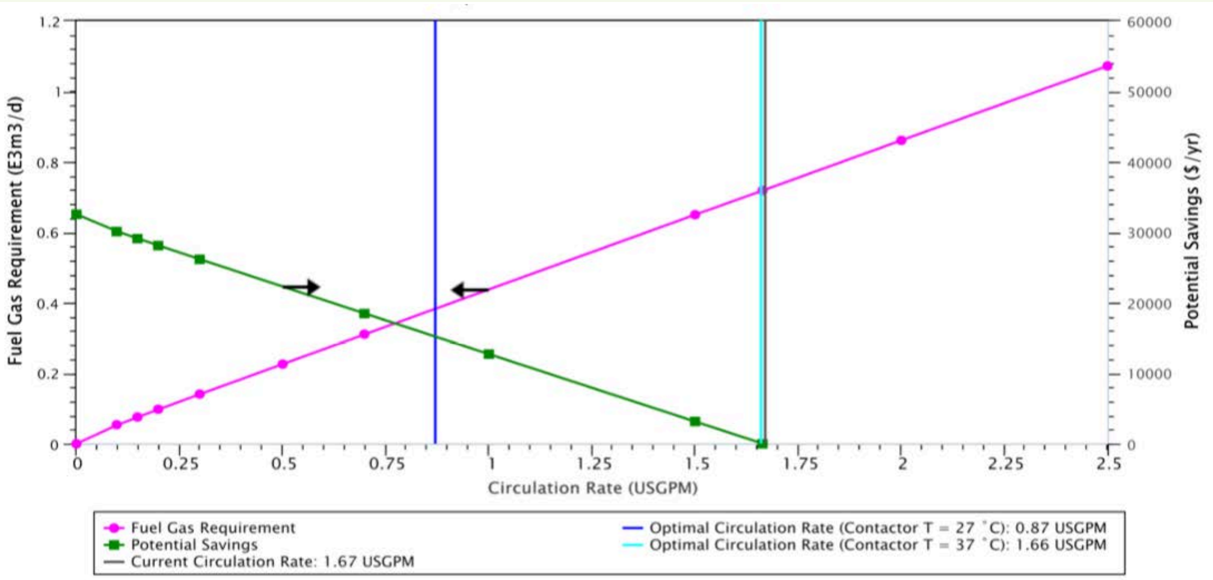

Figure 20 Fuel gas consumption with varying circulation rate

By reducing glycol to the minimum amount that is still sufficient to meet sales gas specifications, operators can save operating cost and reduce methane emissions. Reducing the circulation rate will also result in reduced fuel gas requirements in the still reboiler. Similar to benzene and other aromatic compounds, the amount of methane absorbed and vented is directly proportional to the circulation rate. If the facility operates using a gas-driven pump, then these methane emissions contributions will also be reduced with circulation rate reductions. A recent review by Process Ecology of over 800 operating dehydration plants in Alberta estimates that there is a significant number of facilities (over 100 facilities) that over-circulate glycol and could benefit from glycol rate optimization.

Accurate prediction of dry gas water content is essential for optimization of dehydration units. Reducing the glycol circulation rate below a safe range to accomplish the required water removal can cause major operational problems (e.g. hydrate formation, off- spec gas, etc.); it has been observed that field personnel are reluctant to act on circulation rate reduction opportunities likely as a result of previous negative experience where underestimated dry gas water contents led to freezing problems. As highlighted earlier in this report, rigorous process simulation models provide the required information to determine safe glycol circulation rates and report methane emissions as a function of the circulation rate.

There are a few important engineering reviews that need to be considered in detail before the actual potential for glycol circulation rate can be determined:

- Minimum pumping rate of the installed glycol pump, and
- Minimum turndown at the absorber to ensure proper hydraulic behavior

Both of these aspects are related to the fact that many of the older dehydration facilities are currently operating well below design specifications and the equipment characteristics may dictate how low the circulation rate may be regardless of dehydration performance. The option to replace the pump (downsize) to accommodate a lower circulation rate is reviewed later in this report. The hydraulic performance of the contactor would depend on the relative vapour-liquid rates and the structural features of the column such as diameter, tray type, tray spacing, etc. and although there may be retrofit options available to enable further turndown, these are likely to be costly.

Stripping Gas Reduction

Some dehydrators introduce stripping gas (typically dry fuel gas) in the regenerator to improve the lean glycol purity. This is achieved by adding dry gas which strips water and other absorbed compounds out of the glycol. This practice tends to have a small impact on BTEX emissions but results in a large increase in methane emissions. The benefits of using stripping gas diminish rapidly beyond rates of 2 to 3 scf/gal of TEG solution circulated [16, 25] (See Figure 21).

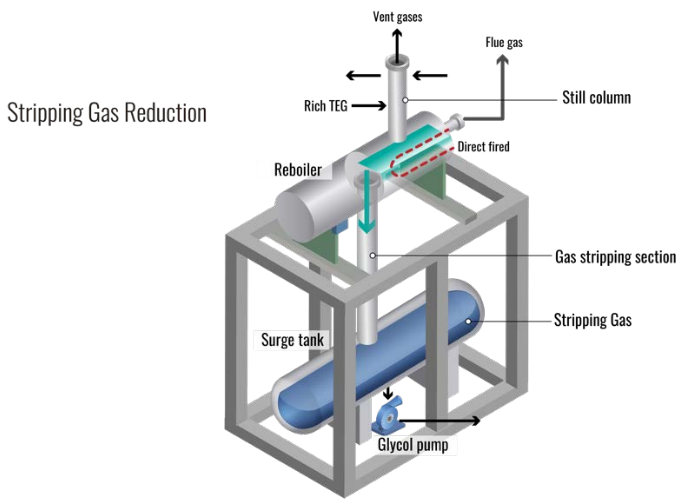

Figure 21 - Typical TEG still column with stripping gas

Glycol concentrations up to 99.6 % w/w can be achieved by sparging stripping gas directly into the reboiler [3, 16]. The use and rates of stripping gas should be evaluated because it is typically emitted directly to atmosphere from the still vent and will therefore significantly increase greenhouse gas emissions due to the high methane concentration of the stripping gas. Charts are available in standard references such as the GPSA data book [13] and other vendor publications [21] and may be consulted for estimating the stripping gas requirements for specified sets of conditions. Reductions in stripping gas consumption can translate directly into methane emissions reductions and operating cost savings. A BMP report issued by the Canadian Association of Petroleum Producers (CAPP) recommends stripping gas rates for TEG systems in the order of 0-0.050 m3/l TEG (0-7 SCF/usg). [7]

It is therefore essential for the optimal operation of the unit to determine whether stripping gas is actually required to achieve the desired dew point suppression. Dehydration plants that handle relatively warm inlet gas will tend to require stripping gas to meet sales gas specifications; in practice it has been observed that a large number of units operate with stripping gas when it is not needed, leading to increased fuel gas use and methane emissions.

A properly tuned process simulation model can be used to determine the need for stripping gas and the inlet gas temperature at which stripping gas would be required. Experience with multiple dehydration plants indicates that in most cases, it is only during summer months when stripping gas is required as the upstream compressor aftercoolers cannot bring the inlet gas temperature to a sufficiently low temperature. Review and reduction of stripping gas use could result in significant methane emissions reductions with no capital cost requirements.

Reboiler Temperature Optimization

Increasing reboiler temperature in the glycol regeneration still column increases glycol purity which in turn could enable a reduction of glycol circulation rate and consequently lower methane emissions. Optimized reboiler temperatures are essential for achieving specification dryness in the product gas. Reboiler temperature deviations, either above or below the optimum temperature range, can make the dehydrator operation inefficient. For TEG, it has been determined that the optimal reboiler temperature should be around 200°C [7, 25]. Temperatures higher than optimum may result in adequate dehydration of the gas stream, but can lead to glycol losses, degradation of glycol, and excess consumption of fuel gas. Lower than optimum temperatures may result in reduced water removal efficiency. Maintaining a reboiler temperature of 200°C will theoretically provide a TEG purity of 98.6% (with no use of stripping gas). The reboiler temperature should be kept at approximately 120°C for ethylene glycol systems (EG), to prevent glycol decomposition and excessive glycol losses (EG becomes viscous at high concentrations, and freezing point decreases above 80% purity).

Other operational considerations related to the reboiler temperature include maintenance factors such as the tuning of the reboiler burner and the quality of the glycol in circulation with particular emphasis on low pH, oxidation, thermal decomposition, and salt contamination, among other aspects [25].

1.3 Process Modifications

This section describes methane emissions reduction options that would require some capital expenditures, in many cases to eliminate equipment constraints that hinder achieving optimal operating conditions.

Glycol Pump Downsizing

There are multiple facilities that are over-circulating glycol and in many of them, the glycol pump has been turned down to the minimum flowrate recommended by pump manufacturers. Assuming that the glycol circulation rate could be further reduced based on an engineering review, and that the absorber can handle additional glycol turndown, this constraint can be removed by replacing the existing pump with a smaller model. Replacing an energy-exchange-driven pump with a smaller model can enable reductions to glycol circulation rates and reduce methane emissions.

Remote field facilities often do not have electrical power and instead use energy exchange pumps to power the lean glycol circulation pump. The energy exchange pump operates using the energy of wet glycol at contactor pressure to drive an equivalent volume of lean glycol at reboiler pressure; this requires additional gas at contactor pressure to overcome frictional losses. The ratio of wet glycol to additional contactor gas required to pump an equivalent volume of dry glycol is approximately two-thirds and one-third respectively.

Kimray pumps [24] are the most widely used gas-driven glycol pumps and they use high pressure gas from the dehydration unit to drive the pistons. In Kimray pumps, the gas is entrained in the rich glycol which is then released at the regeneration still vent and/or the flash tank (if present).

In order to evaluate the volume of gas that is vented at standard conditions, Kimray provides a set of emission factors as a function of the operating pressure. An evaluation of a "typical" dehydration plant in Western Canada [3] indicates that the reported factors imply assumptions of ideal gas behaviour. When compared to more rigorous calculations using process simulation, some significant deviations for units operating at higher pressures were revealed. When evaluating the methane emissions reductions that may be achieved by switching to a smaller pump, we note that the reported Kimray factors are accurate for lower pressures while introducing more significant errors at higher pressures. The methane volumes reported by a rigorous simulation model will tend to be higher, particularly at higher pressures where deviations from ideality are more pronounced. The glycol pumps can usually be installed without the need to shut in production as dehydration plants would normally have a spare pump that can be used while the new one is installed. Alternatively, an electric-driven pump may be installed which would increase system efficiency and further reduce onsite emissions, provided there is a readily available source of electricity [35]. This option is reviewed next.

Glycol Pump Electrification

Similar to the pump downsizing option, switching to an electric pump eliminates the additional high-pressure gas demand and therefore reduces methane emissions, but may not always be an option, if electric power is not available. The replacement of an energy exchange pump with an electric-driven positive displacement pump could be an effective option but in our experience these projects are less cost-effective, even when power is available.

In contrast to gas-assisted pumps, electric motor driven pumps have less design-inherent emissions and no pathway for contamination of lean TEG by the rich stream. Electric pumps only move the lean TEG stream; the rich TEG flows by pressure drop directly to the regenerator and contains only methane and hydrocarbons absorbed in the contactor.

Electricity to power an electric pump can be purchased from a local grid or generated onsite using lease or casing head gas that might otherwise be flared. If a source of electricity is available or can be obtained cost-effectively, then this option may be more attractive. The correct pump size for a dehydrator system should be calculated based on the circulation rate and the operating pressure of the system. The Natural Gas Star program reports on parameters to calculate the required horsepower needed for these pumps and reports on benefits related to reduced natural gas losses, increased operational efficiency, reduced maintenance costs, and reduced regulatory compliance costs [35,36].

Flash Tank Installation

The main purpose of a flash tank is to remove both free and/or dissolved gas from the rich glycol stream at an intermediary pressure for resource conservation and/or emission reductions. This is accomplished by the installation of a two-phase flash separator located downstream of the rich glycol exit of the glycol contactor. If significant amounts of hydrocarbon liquids are encountered at this point, the flash tank should be designed for three-phase separation. Otherwise, the hydrocarbon liquids could cause problems in the reboiler and lead to reduced boiler efficiency and increased combustion emissions. In a flash tank separator, gas and liquid are separated at either the fuel gas system pressure or a compressor suction pressure of 40 to 100 psig [36]. At this lower pressure and without added heat, the gas is rich in methane and lighter VOCs but water remains in solution with the TEG. The flash tank typically captures approximately 90 percent of the methane and 10 to 40 percent of the VOCs entrained by the TEG, when the flash tank off gas is recycled or combusted emissions from the dehy would be reduced. The rich TEG, largely depleted of methane and light hydrocarbons, flows to the glycol reboiler/regenerator where it is heated to boil off the absorbed water, remaining methane, and VOCs.

The separated flash gas is most commonly used as fuel or sent to flare for disposal or in some cases recycled to the facility inlet. The amount of vapour flashed is maximized by operating the flash at the lowest pressure and highest temperature possible. In the case of dehydrators with a flash tank installed, it is crucial to correctly identify the fate of the flash gas as it will be mainly composed of methane.

Additional benefits of installing a flash tank include reductions in operating cost by using the gas recovered in the flash tank for fuel gas or, alternatively piping the recovered flash tank gas to the suction of an upstream compressors (a common design practice in new installations) reduces production costs.

Finally, the addition of a flash tank can reduce benzene emissions when the still overhead is routed to a condenser, since the flash tank removes non-condensables which would otherwise diminish the benzene emissions reduction in the condenser.

1.4 Thermal Combustion

The methane emitted from the still column vent may be destroyed by routing the vent stream to a suitable continuous oxidation unit such as:

- Low-pressure flare system
- Thermal incinerator unit
- Other combustion commercial systems which may provide advantages over standard flare/incinerator (e.g., Natco SHV Flare System)

Both flaring and incineration have been used successfully for combusting still overhead vapors and can be designed with automatic ignition systems to ensure a continuous flame. There are some advantages to an incinerator over a flare:

- The low discharge pressure of the dehydrator still column provides little energy to drive the vent gas to a flare. If an incinerator is used, spacing requirements typically allow it to be located much closer to the still column than a flare, and there is generally enough natural draft for the vapors to flow to the unit unassisted.
- The high water content of the gas may lead to freeze-off of the flare line during winter operation unless the system is heat traced or designed for dedicated dehydrator service (i.e., the flare line is sloped and insulated so any water that condenses will drain back into the dehydrator). A dedicated incinerator can be safely placed much closer to the dehydrator to help reduce the corresponding cost.
- Incinerators are able to provide better destruction efficiencies than flare systems and are more aesthetically appealing since there is no visible flame.
- Destruction efficiency in flares may be adversely affected during periods of strong winds.

Conversely, some advantages of a flare over an incinerator include:

- Flares are generally less costly to install than incinerators.
- Flares require less frequent maintenance and monitoring to ensure proper operation.

Examples of specific technologies that have been successfully applied to combust the dehydrator vent streams include the following:

NATCO SHV Flare System

"The NATCO SHV (Superheated Vapor) Flare system virtually eliminates liquid collection/disposal and provides 95% to 98% BTEX and VOC destruction efficiency. The improved process for flaring of the vent gas stream utilizes waste heat from reboiler exhaust stack to superheat the vapours to allow proper oxidation of the hydrocarbons. It also reduces or eliminates still column back pressure resulting in maximum glycol purity and provides a smokeless flame." [29]

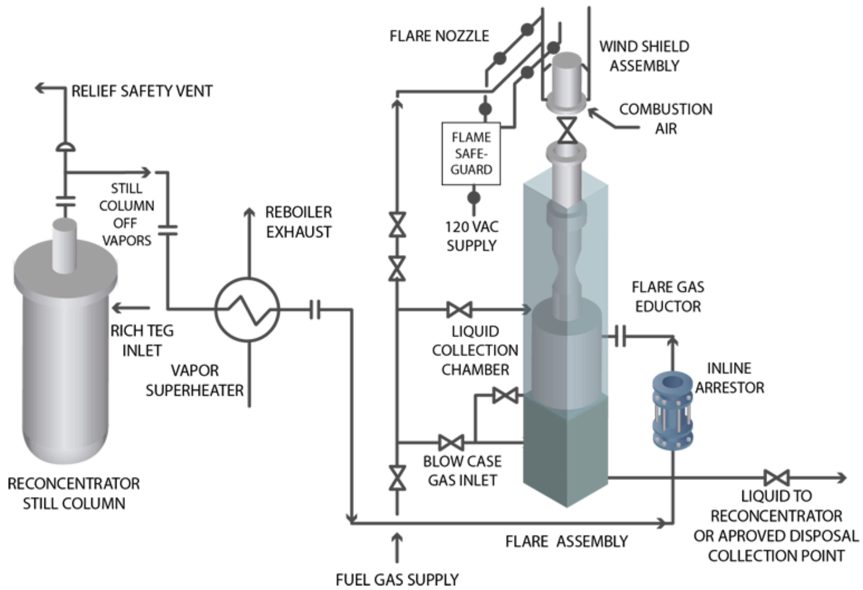

Figure 22 - Typical Flow Diagram - SHV Flare System [29]

"As shown in Figure 22, the vented gases from the still column, which are a combination of liquids and vapors (stream 12) are separated from the glycol during regeneration, flow to an integral exchanger (vapor superheater) where they are heated by the exhaust from the reboiler burner (stream 13). The superheated vapors are piped through an Inline Arrestor which retards flame propagation (stream 14).
The vapor and condensate liquid flow into the flare inlet (stream 15). The liquids are gravity fed into the liquid collection chamber (blowcase) in the base of the flare support. The superheated vapors are inspirated to the low pressure side of the flare gas eductor (stream 17). Natural gas (stream 16) is used as supplemental fuel, increasing the heating value of the waste gas stream to a level required for complete combustion. Recovered condensed liquids are separated from the superheated vapor flowing into the blowcase (stream 18) located in the bottom of the flare base. The nominal amount of liquid is sent to an acceptable collection point for disposal (stream 19).
The external vapor superheater (stack heat exchanger) reduces liquid accumulation and disposal, enhances clean burn and water vaporization and operates in cold weather (no freezing)."

TCI Incinerators

"The TCI product is an environmentally friendly alternative to flaring. Combustion efficiency is 99.8% resulting in no smoke, no odor and no visible flame during normal operations. This is a preferred method when operating in sensitive areas such as near residents. TCI products are also robust, simple to use and require very little maintenance. Some of the standard features of the TCI incinerator includes:

- Electronic flame failure ignition system, reliable ignition
- Natural draft, no blower needed.
- Venturi aspirated burners, good premixing of waste gas and air.

- Combustion efficiency is reported to be 99.8%

Total Combustion Inc. incinerators are used to effectively combust waste gases containing volatile organic compounds (VOCs), benzene, toluene, ethylbenzene, and xylenes (BTEXs) from oil and gas equipment, such as storage tanks, casing gas, dehydrators, pneumatic devices, well testing, tanker loading activity, and pipeline blowdowns.

Total Combustion Inc. incinerators use venturi aspirated burners for good premixing of waste gas and air, and do not require combustion air blowers. Power to operate the B149.3 compliant burner management system can be supplied by a small solar power system. These incinerators have been third party tested to comply with AER D-60, and Saskatchewan S-10 / S-20 regulations" [26].

Black Gold Rush Industries' enclosed vapour combustors (EVCs)

"Black Gold Rush Industries' enclosed vapour combustors (EVCs) effectively combust volatile organic compounds (VOCs) and benzene, toluene, ethylbenzene, and xylenes (BTEXs) produced from oil and gas equipment, such as storage tanks, casing gas, dehydrators, pneumatic devices, pumps or any other low-pressure venting equipment. Black Gold Rush's EVC is an effective alternative to expensive and sometimes unreliable vapour recovery units (VRUs) and incinerators. The combustors can be placed within 12m of existing process equipment and do not require expensive valve train or piping. The patented burner system achieves 99.99% total hydrocarbon destruction with as low as 2oz of pressure. No additional fuel gas, air assist, or power is required" [26].

There are other product manufacturers that can deliver thermal oxidation devices with varying degrees of destruction and cost efficiency.

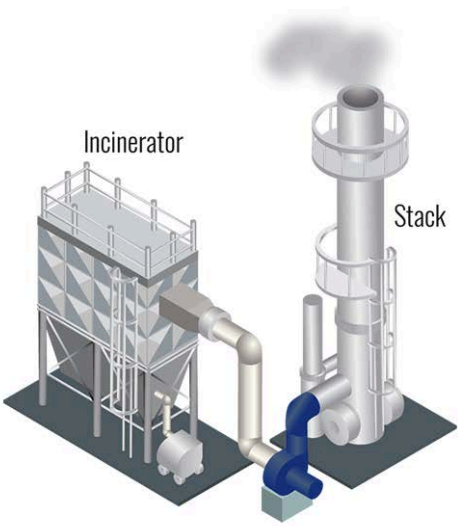

Figure 23- Typical incinerator configuration

1.5 Vapor recovery/ Combustion

There is a related set of technologies that rely on recovering the still overhead gas for use as fuel gas after condensation steps. These technologies can be further classified depending on the main purpose of the recovered fuel gas. Main applications include the use of the recovered gas as fuel in the reboiler burner of the dehydration regeneration step and as supplementary fuel to natural gas compressor engines as described next.

Black Gold Rush Industries' Rush Burners

"The Rush Burners effectively combust volatile organic compounds (VOCs) and benzene, toluene, ethylbenzene, and xylene (BTEXs) produced from oil and gas equipment, such as storage tanks, casing gas, dehys, pneumatic devices, pumps, or any other low-pressure venting equipment while providing heat to line heaters, tank burners, dehys, free-water knockouts, reboilers, and heater treaters." [26]

The installation of these burners however is likely to require a liquid condensation step upstream of the burner.

Kenilworth Combustion Module

In this and other similar technologies, the gas from the glycol reboiler stack is sent to a condenser to remove free liquids and the overhead gas is then piped to a glycol reboiler burner system as a primary source of fuel. For the Kenilworth burner there must be an existing condensing tank.

A key consideration is to match the amount of gas from the vent with the required burner gas. In this technology, "the captured gas is used as a low-pressure process fuel with a "99.9% destruction rate". The Kenilworth combustion system ranging from under 1 MMBTU/hr to up to 10 MMBTU/hr includes:

- Flame Scavenger Low Pressure Burner which is utilized in systems under 0.9 MMBTU/hr
- Condensing Unit w/Integrated Storage Tank

Saturated gas off the glycol reboiler stack enters the Condensing Unit. The gas is collected in a 100 bbl condenser tank where water and HC liquids drop out. The gas is then piped to the glycol reboiler burner system (placing a slight back pressure on the still vent of approximately 1.5 oz/in2) for use as fuel. The reboiler burner fuel supply system is designed so that vent gas containing BTEX acts as the primary source of fuel and sweet dry fuel gas sourced from the facility supply header acts as a back-up when additional heat is required. The burner is a Triple Stage Natural Draft Burner which allows high pressure gas in through one port, and the low pressure still column vapors in through a second port. [23] A Kenilworth module captures the gas emissions from the still vent and returns it as a low-pressure fuel gas to the system.

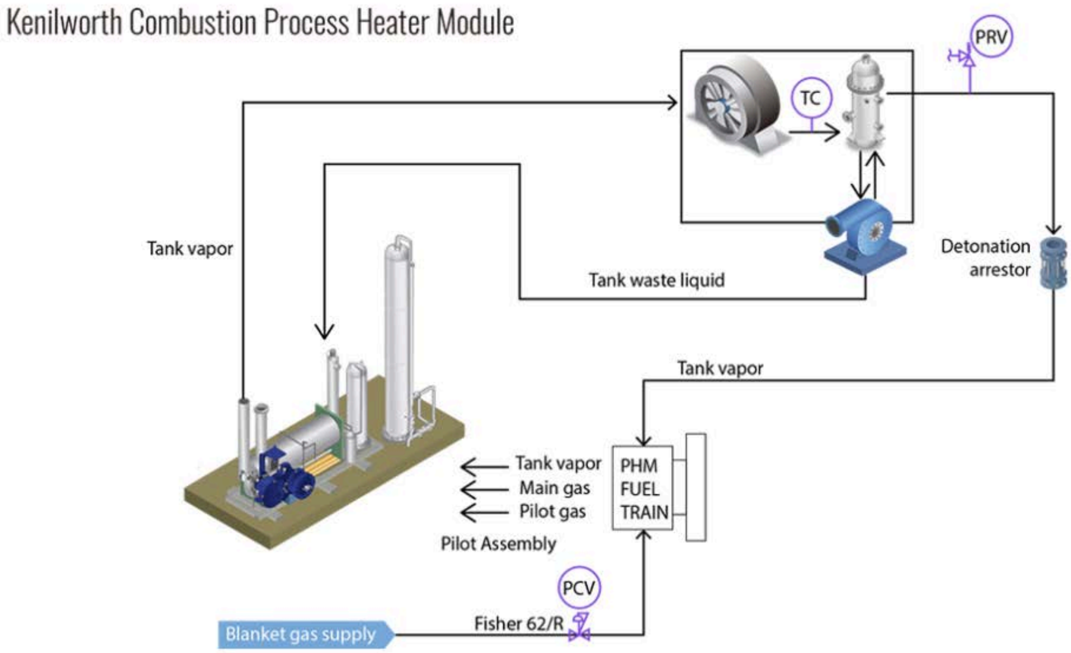

Figure 24- Kenilworth combustion process heater module

Slipstream GTS-DeHy

The Slipstream GTS-DeHy is an enclosed combustion technology that utilizes the vent gases from the dehydrator still column for use as supplementary fuel in the regenerator burner. It is comprised of a burner management control system, high- and low-pressure burners, and an auxiliary burner. Additional options may include a liquid knockout system such as an aerial cooler upstream of the burner management system.

The technology is designed to handle variations in flow rate and gas composition from the still column while meeting the heat demands of the regenerator burner. It is primarily designed as an emission control device with the added benefit of utilizing the heating value inherent in the still column vent stream to offset fuel gas use by the burner.

The technology works by taking the still column vapors and routing them to either the low-pressure burner when the regenerator burner is firing, or to the auxiliary burner located in the exhaust stack of the regenerator burner. In the event the still column vapors cannot provide enough process heat, there is a high-pressure burner available. In this manner, methane and BTEX vapors are always combusted; either providing supplemental process heat when routed to the burner, or simply being burned in the auxiliary burner which acts like a shrouded flare or incinerator.

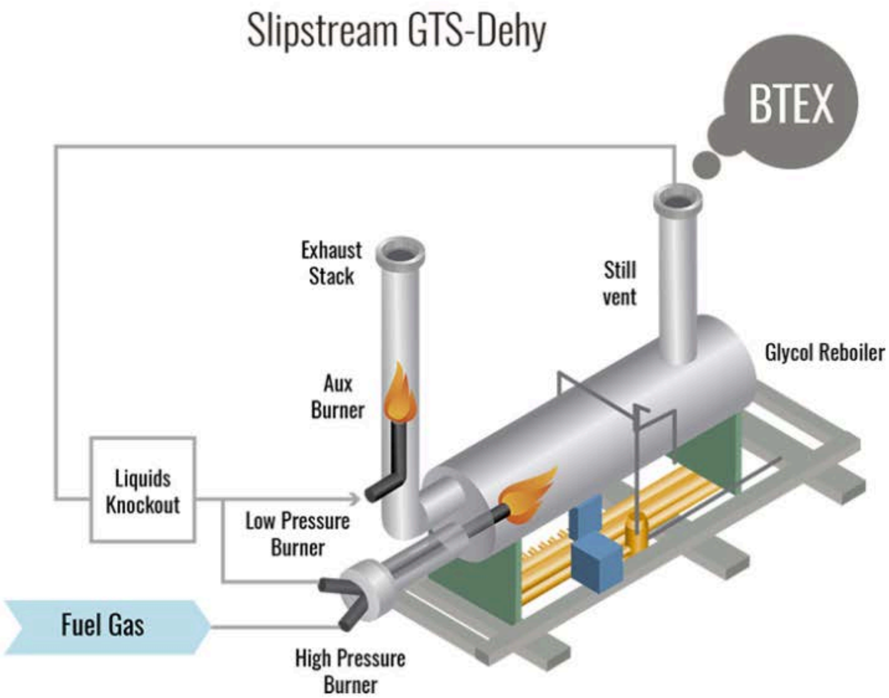

Figure 25 Slipstream GTS-Dehy

"The GTS-DeHy easily integrates into new or existing installations, eliminating the need for stand-alone combustors or costly vent gas compressors. On a typical glycol dehydrator application, the GTS-DeHy routes the captured vent gases to either the main burner or auxiliary burner depending on heat demand and has a BTEX destruction efficiency of 99.5%" [28, 31].

NATCO BTEX BUSTER

The NATCO BTEX BUSTER emission control system provides a BTEX removal efficiency greater than 99.7%, helps recover and collect saleable liquid hydrocarbons, and prevents the loss of expensive fuel gas from glycol reconcentrator vent emissions [30].

The vapors emitted from the glycol still column are cooled in the natural draft air cooler to temperatures below 120 degF [49 degC]. The condensed liquids are collected in a small two-phase separator and pumped to customer storage. Noncondensable gases from the separator are piped through an in-line flash arrestor and then burned in the glycol reboiler firebox to achieve an overall minimum destruction efficiency of 99.7% and greater. This technology incorporates burner accessories to help prevent sooting and back pressure on the regeneration system.

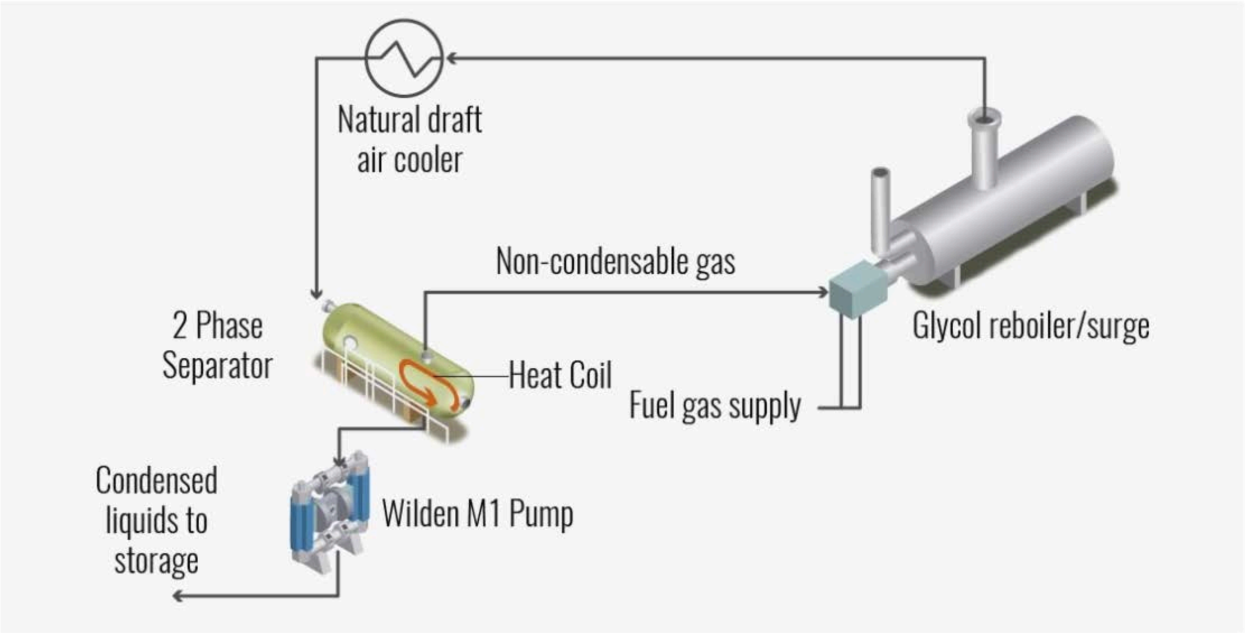

Figure 26- NATCO BTEX buster

Jatco BTEX Eliminator

The Jatco BTEX Eliminator system is a closed loop, counter flow heat exchanger and condensing system used to capture and recycle BTEX and VOC vapours from the glycol dehydrator still column. A Jatco BTEX Eliminator captures the gas emissions from the still vent and feeds it through an air-cooled exchanger where condensable liquids are dropped out. The condensed liquids gravity-drain into a blow-case placed at the base of the condenser. The blow-case purges these liquids automatically, most commonly to a storage tank. The vapours remaining uncondensed may then be routed to a combustion source such as a low-pressure burner, flare, or incinerator.

The remaining vapors are fed through a closed-loop system that must go to a low-pressure destination such as the fuel gas inlet or still column reboiler burner. Uncondensed vapors are routed through a separation and filtering media to the main burner for fuel assist while the burner is operating [22].

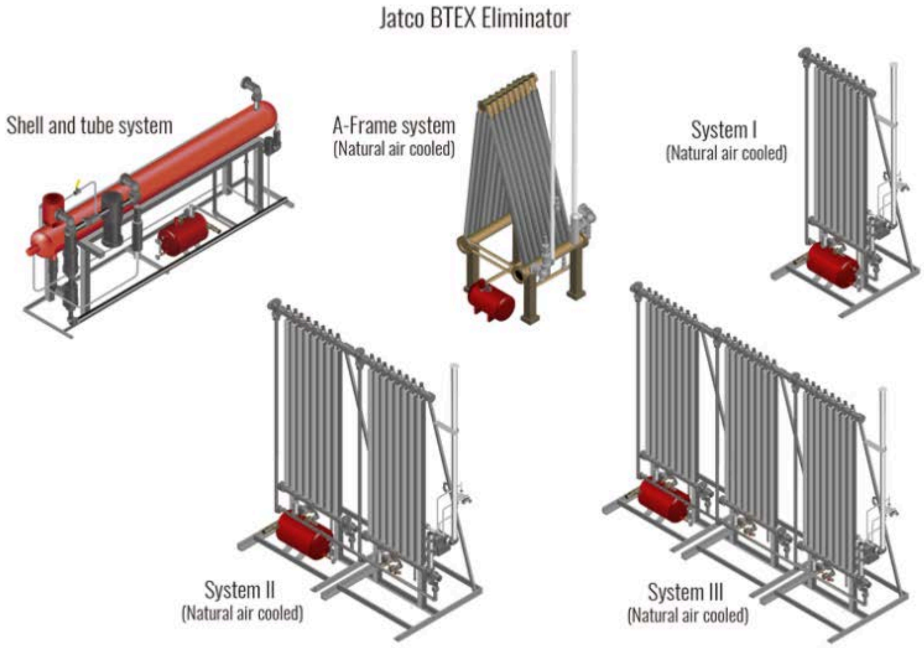

Figure 27 Jatco BTEX Eliminator configurations

Slipstream

Slipstream technology (REM Technology Inc.) utilizes the vented hydrocarbons as a supplementary fuel source for natural gas engines and monitors and controls the addition of these vented hydrocarbons to ensure safe and reliable engine operation. According to Spartan Controls, for most systems, the added fuel from using this technology is typically less than 10% of engine fuel, but up to 50% of engine fuel can potentially come from the vented sources. If a facility has both a TEG dehydration unit and natural gas reciprocating engines (driving a compressor), the still column overhead can be used as fuel gas in those engines. This technology results in significant methane reductions as well as reductions in other pollutants (such as BTEX).

The SlipStream system is adaptable to handle vented emissions from various sources. Typical vented sources include: compressor packing vents, liquid storage tanks, glycol dehydrators, cactus dryers, instrument vents, and chemical injection pumps [26, 28].

Vapor Recovery Unit (VRU)

The objective of installing conventional vapour recovery units (VRUs) is to reduce methane, VOCs, and BTEX emissions from flash tank separators and still columns by recompressing still column overheads and recycling them to the facility inlet gas compressor suction.

A Vapor Recovery Unit (VRU) has the advantage of potentially recovering all still column overhead vapor. Types of vapor recovery units include:

- Conventional VRU: uses a screw or vane compressor to extract vapors out of the atmospheric pressure vessel; requires electrical power or an engine driver.
- Venturi ejector VRU (EVRU) or Vapor Jet uses venturi jet ejectors in place of rotary compressors. EVRU requires a source of high-pressure motive gas and an intermediate pressure discharge system. Vapor Jet requires a high-pressure motive liquid.

The VRU boosts the recovered gas pressure enough to inject it into a fuel gas system, compressor suction, or gathering/sales line.

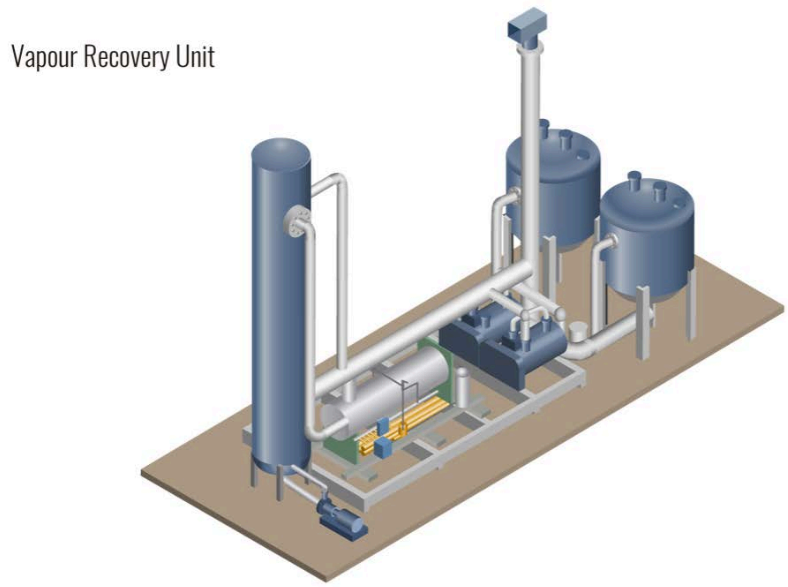

Figure 28 Vapor recovery unit schematic

Conventional VRU units used in dehydration facilities consist of a still column vent cooler, still column vent tank, VRU scrubber(s), VRU compressor, and after cooler(s).

The compressor types most commonly used for VRUs are either flooded rotary screws or rotary sliding vanes. A reciprocating compressor is used instead in some technologies (e.g. GasPro VRU) which have the advantage of enabling higher discharge pressures. Figure 29 shows the operating ranges of different compressor types typically used in VRUs. The equipment and maintenance costs of reciprocating compressors are often lower than other types of VRU compressors, especially because operations personnel are generally more familiar with reciprocating compressors, have associated maintenance training, and replacement equipment is usually more readily available [26].

VRU Compressor Type	Horsepower Range	Maximum Discharge Pressure (psig)	Volume Range (MSCFD)
Flooded Rotary Screw	5-1000	300 (single stage)	20 – 2500
Rotary Sliding Vane	5-600	55 (single stage)	15 – 2000
Vapour Jet Pump	NA	40 (single stage)	5 – 75
Reciprocating Compressor	5-2000	4500 (multi-stage)	2 - 20,000+

* Based on natural gas with specific gravity of 0.65, inlet gas at 60°F and 0 psig.

Figure 29 Operating ranges for compressors

Gas Pro Compression BTEX VRU

Gas Pro compression has developed a BTEX VRU system that allows 100% recovery of the emissions from the glycol regenerator. In this system, the regenerator emissions are condensed and then sent into a separator where the liquids drop out. The uncondensed vapor above the liquid then goes into a compressor, which delivers the gas back into the inlet of the facility. The condensed liquids from the separator are pumped to a storage tank.

As shown in the figure below, the still column overheads from the two dehydration units are combined and directed to the GasPro BTEX Air Cooler (E-900) where the overheads are cooled and condensed to liquid (mostly water). The liquid is then sent to the GasPro Scrubber (V-900). In the scrubber, the condensed liquid is separated from the uncondensed vapour and the liquid is then sent to the facility's produced water storage tank via two gear pumps (P-900/901). The uncondensed vapour from the scrubber is routed to the GasPro reciprocating compressor (K-900) to increase the pressure of the vapour stream so that it can be pushed into the suction of the facility overhead compressor and eventually recycled to the inlet of the facility. The compressed vapour from the GasPro BTEX VRU is cooled in After Cooler (E-901) to remove the heat of compression before being directed to the suction of the facility overhead compressor.

In the GasPro VRU technology, the need for a still vent tank is eliminated and replaced by an air-cooler to properly cool the vapour stream. This potentially results in lower capital cost and a correspondingly shorter payback period than a conventional VRU. Using a properly sized air-cooled heat-exchanger helps to control the cooling process and enhance vapour condensation and thus leads to a higher BTEX reduction efficiency than still vent tanks.

The GasPro technology recompresses and recycles the still gas vent, eliminating the emissions of BTEX from still columns in dehydration systems [27].

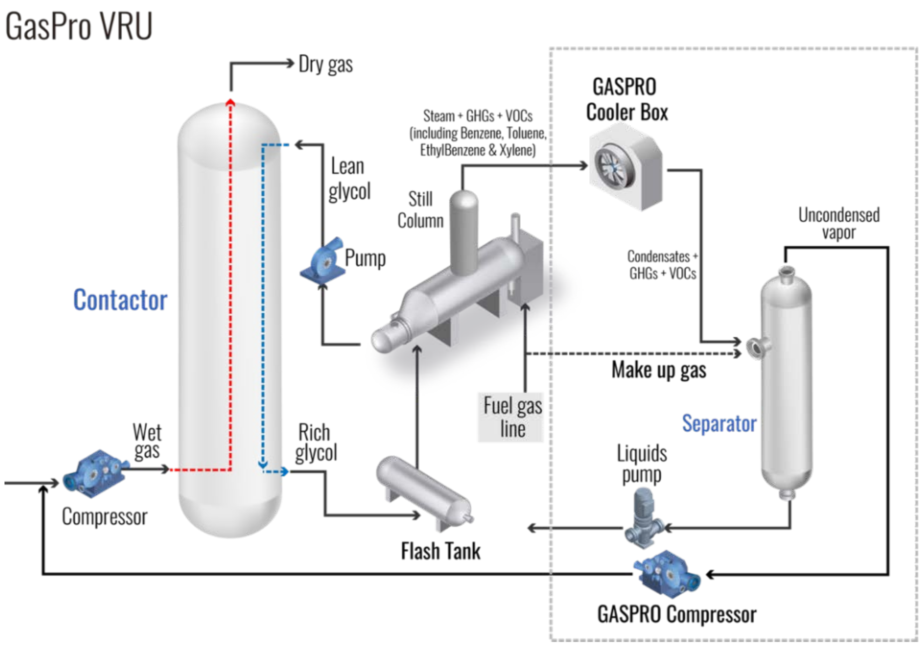

Figure 30 GasPro VRU system

1.6 Discussion around emissions control technologies

The selection of the best technology to install at a given facility will depend on several factors such as plant lifetime, hardware specifications, plant layout, regulatory constraints, corporate policies, and many other factors. All of these technologies have the potential to help reduce methane emissions from dehys.

In order to provide guidelines regarding methane abatement cost from glycol dehydration, fuel gas, and methane emissions, reductions were calculated based on process simulation results. Some of these technologies have also been validated via pilot projects and measurement and in these cases the process simulation results are adjusted to match the experimental results[2]. Fuel gas savings and methane emissions reductions resulting from reducing glycol circulation rate were determined by applying heuristic rules to calculate the "optimal" glycol circulation rate and by comparing this yardstick to "actual" circulation rate, emissions reductions can be estimated. For the case of energy exchange pumps, the reduced contribution of methane to the dehydration vents was estimated using the manufacturers' gas consumption data for pressure and circulation rate (Kimray). The burner fuel gas was calculated assuming 60% combustion efficiency, using the simulator-predicted reboiler duty. The following sections summarize some of the findings uncovered by other studies that can provide useful lessons learned for future applications. As the technologies continue to evolve it is highly recommended to validate both technical and economic aspects directly with vendors ahead of a final decision.

[2] Slipstream Report and GasPro PTAC Report

Low pressure burners

- The Kenilworth systems were not the correct choice for systems with energy exchange pumps because these pumps generated more gas to be burned than the burner requires to regenerate the glycol. The balance between available vent gas and required reboiler fuel gas needs to be evaluated.
- The Jatco system provided an engineered heat exchanger; in one particular installation, combined with an Eclipse burner, it proved to be effective.
- There have been reports of challenges with the low-pressure burners and condensation of recovered gas. The gas recovered from the condenser overhead was not always a reliable source of secondary fuel, so operations would bypass the system in cold weather.
- It was necessary to ensure that the piping was correctly sloped such that condensed (and possibly burnable) liquids would flow back to the condenser, rather than to the burner.
- These systems would be more economic at larger facilities.

Flash tank tie-in

- Where there is no glycol flash tank, this option can be used to recover vapors that can then be introduced to the fuel gas system or flare header. Otherwise these vapors are vented from the still.
- Alternatively, where a glycol flash tank exists, but the flash overhead is not recovered (e.g. sent to flare), it can be economic to recover the flash vapors and route it to the fuel gas system.
- This can potentially be an economically viable option, depending on factors such as size of facility and existing configuration.
- New facilities should employ flash tanks to recover the light hydrocarbons.

Still overheads to Slipstream

- For this option, there needs to be a condenser (e.g., TankSafe) in place, as well as proximity to a compressor engine.
- For many applications, this has been a successful option, reliably providing significant methane emissions reductions.
- Where stripping gas is needed to ensure sufficient dehydration, Slipstream effectively recovers this gas.
- This system works very well to reduce GHG emissions, reduce fuel gas use, and increase production while removing virtually all benzene and other hydrocarbon emissions from the dehydrator.
- Some operators have reported challenges with the sophisticated control system and the increased reliance on vendor assistance to ensure proper operation.

Energy exchange pump rate reduction

- Pump rate reduction can be employed at facilities that are over-circulating glycol (a significant number of dehydration facilities are over-circulating). Depending on the pump characteristics, in some cases, the circulation rate can be turned down, while in others, pump replacement would be needed.
- It is necessary to ensure that the contactor performs adequately at low rates.

- There is also an opportunity to turn down electric pumps, although the methane reduction benefit is not as significant as for energy exchange pumps.

In all cases, operator buy-in is critical to ensure that they understand and trust the proposed modifications, with a better chance of ensuring long-term success.

The biggest opportunities for methane emissions reductions come with facilities where the following contributing factors are present:

- Use of energy exchange pumps with no flash tank
- Use of stripping gas
- Still overhead venting to atmosphere
- Large glycol circulation rate with significant over circulation

4.1.Marginal Abatement Cost Curve

The impact of each technology on methane emissions reduction was evaluated by applying the reported destruction efficiency to the base case described above.

Reported fixed costs include best estimates of equipment costs, installation costs, and cost of engineering studies. Fixed costs are converted to annualized costs by assuming a unit life of 10 years and a gas price of $3/GJ. Operating costs include both operating and maintenance costs. Several of these cost estimates come from industry partners which have successfully installed these mitigation options at their dehydrator or refrigerator units. Cost estimates also come from published reports [9,15, 27, 34, 35, 36].

In Figure 31, for each technology, the mass of methane that could be reduced is estimated and plotted as length along the x-axis. The marginal abatement cost is the net of the cost savings from reduced fuel consumption and the fixed and variable costs from implementing the technology. The technologies are sorted in order of ascending abatement cost from left to right. The reported methane reductions are relative to a "typical" dehydration unit where the maximum methane emissions reduction (approximately 130 tonnes CH4/y) is achieved by installing a VRU system. Varying unit configurations and operating practices may result in different ranking of the technologies reviewed.

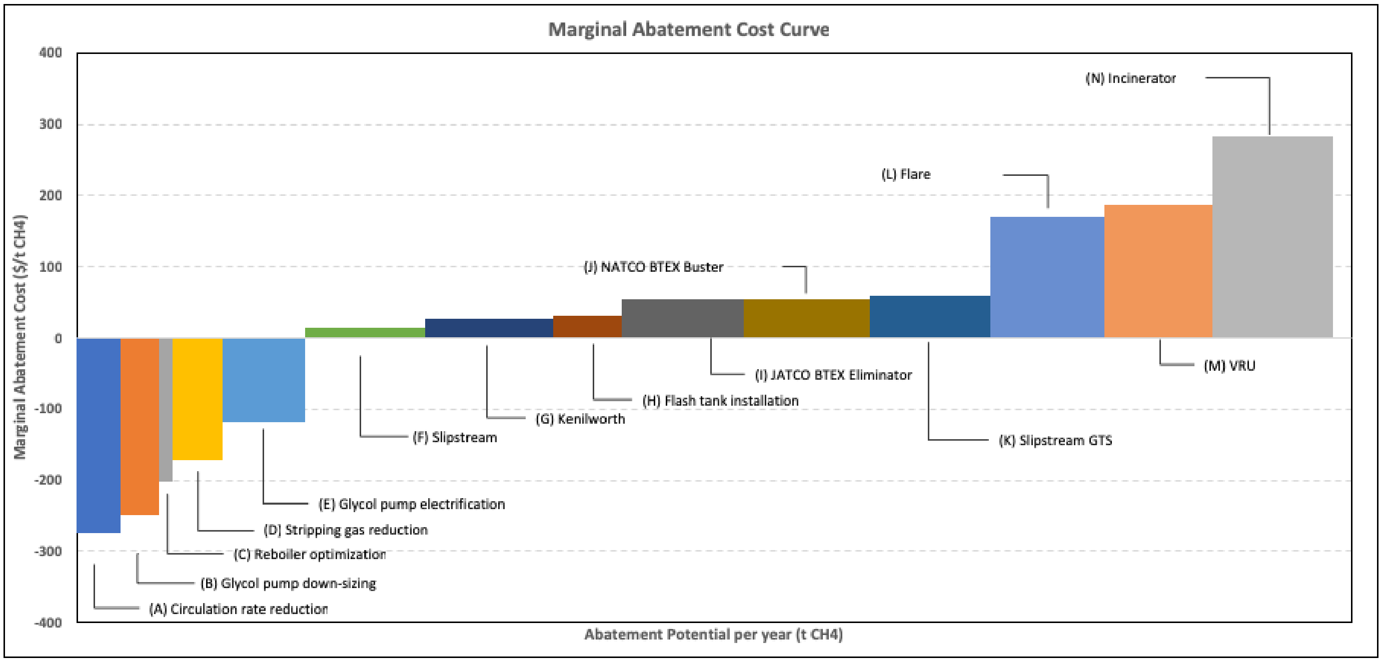

Figure 31 Marginal Abatement Cost Curve for Methane Reduction Technologies

It can be seen from Figure 31 that there are several process optimization actions that reduce both costs and methane emissions concurrently, including circulation rate reduction, reboiler temperature optimization, and stripping gas reduction. Although a small cost will be required to perform studies on optimal operating conditions, the implementation of these optimization results will almost certainly reduce costs over the long term. Flares, incinerators, and VRUs are already relatively common and can provide high methane reduction potential but display higher abatement costs. Some of the proprietary technologies studied here such as NATCO BTEX Buster and Slipstream offer good methane reduction potential at significantly lower costs. Although several of these technologies have similar functions (e.g. capture still vent gas, condense it and combust it at the reboiler), our estimates show that total life cycle costs can vary after considering unit costs, installation, maintenance and utilities. Some of the cost estimates presented here are based on previous installation experience only and may not reflect all products that are currently on the market. Operators are encouraged to do their own research and receive their quotes from vendors when choosing which unit offers the lowest marginal abatement costs.

Of the technologies reviewed, the most cost-efficient methane reduction opportunity for potential widespread adoption in industry is the reduction of glycol circulation rates, including cases for energy exchange pump downsizing. Review and elimination of the use of stripping gas is also an effective strategy that operators can pursue to significantly reduce methane emissions. It is also noted that in addition to methane reductions, significant reductions in benzene emissions can be achieved by implementing these technologies.

4.2.Marginal Abatement Cost Curve- Assumptions

This section describes in more detail the assumptions and considerations taken when evaluating the marginal cost of abatement for each one of the technology options displayed in Figure 31. Each one of the options was evaluated independent from each other; e.g. installing a flash tank would take place without optimizing glycol circulation rate but at current operating conditions.

- Glycol circulation rate reduction

This option considers that the existing energy-exchange glycol pump can be turned down from the current circulation rate to the "optimal" circulation rate as defined earlier. The reported methane emissions reductions are due to the reduced volume of gas demanded by the pump as well as some reductions in the absorbed methane in the contactor, due to lower glycol rates. Depending on the pressure of the system, these reductions would change significantly; the higher-pressure dehydrators would be an even more attractive target for circulation rate reductions. The economic benefits include savings in fuel gas for the pump and also fuel gas savings at the reboiler burner. It is noted that for this evaluation, the stripping gas rate was kept constant with reduced circulation rate.

- Glycol pump downsizing

Similar to the circulation rate reduction, this option assumes that the existing energy exchange glycol pump is operating at its minimum flow rate and that any further reductions in circulation rate to achieve the "optimal" rate would require a pump replacement. The benefits in terms of methane emissions reductions and fuel gas savings would be equivalent.

- Reboiler temperature optimization

Although difficult to quantify, adjusting the reboiler temperature to the optimal values would enable further glycol circulation rate reductions. It is noted that this change in the process would not result directly in methane emissions reductions directly but only after the circulation rate has been reduced.

- Stripping gas reduction/ elimination

In this option the assumption has been made that the stripping gas can be completely turned off with no negative effects in dry gas water content. As noted earlier, glycol circulation rate has been kept constant at the current base case rate such that the methane emissions reductions are directly attributable to the stripping gas.

- Glycol pump electrification

This option assumes that there is available power on site and the installation cost includes only the pump itself. Clearly electrification of a site could prove to be uneconomic for remote locations with no access to grid power. The reductions in methane emissions for this option are much larger than the energy exchange pumps as all of the gas used for driving the glycol loop would be eliminated with some incremental operating cost due to electricity use.

- Slipstream/ Slipstream GTS

The main assumption regarding Slipstream vs Slipstream GTS lies in the use of the recovered gas. It has been assumed that all of the recovered gas from the dehydrator vent would replace fuel gas at the facility with the full economic benefit in fuel gas savings. However, in the case of Slipstream GTS it is noted that the quantity of recovered gas typically exceeds the fuel gas requirements of the reboiler burner and as such the economic benefit of the GTS option has been limited to this maximum fuel gas demand.

- Kenilworth/ JATCO BTEX Eliminator/ NATCO BTEX buster

Similar to the Slipstream GTS, these technologies are designed to capture the vented gases and use it as fuel gas in the reboiler burner. Thus, the economic benefit in terms of fuel gas savings is limited by the reboiler burner demand while the methane emissions reductions achieved are very similar.

- Flash tank installation

This option would enable the methane to be captured before the still vent with the main assumption being that the recovered gas is recompressed and recycled to the inlet of the facility. This assumption implies that there are no economic benefits in terms of fuel gas savings. However, if the recovered gas is used as fuel gas then the marginal abatement cost of this option would improve.

- Flare/Incineration

Although effective in methane destruction, these options are costlier and provide no benefit in terms of fuel gas use. In contrast to technologies that enable gas recovery, these technologies would incur an increase in fuel gas consumption.

- VRU

The installation of a vapor recovery unit captures all of the methane emissions making it a very effective technology. However, there is no fuel gas savings impact to offset the higher capital expenditures. The assumption is made that the captured gas is recycled to the inlet of the facility and although this means that additional gas can go to the sales line, no economic benefit was included in this report.

5. Cost data

The following average costs were considered for the evaluation of marginal abatement costs for each technology as applied to the base case:

Table 14- Marginal abatement cost data

Technology	Methane reductions (tonnes/y)	CapEx ($)	OpEx ($/yr)	Fuel gas savings[3] ($/yr)
Circulation rate reduction	40.2	1,000[4]	0	11,151
Stripping gas reduction/ elimination	49.4[5]	1,000	0	8,601
Reboiler temperature	10.0	1,000	0	2,126
Glycol pump electrification	87.1	43,778	500	15,168
Glycol pump down-sizing	40.2	11,735	0	11,151
Flash tank installation	69.2	17,756	300	0[6]
Flare	119.8	162,500	4,200	0
Incineration	123.6	300,000	5,000	0
Kenilworth	126	109,167	1,350	8,790[7]
JATCO	126	135,325	2,000	8,790
Slipstream GTS	125.5	146,625	1,500	8,790
NATCO	125.8	150,000	750	8,790
VRU	126.1	203,333	3,320	0
Slipstream	125.5	225,000	1,200	21,932[8]

[3] Fuel gas savings includes stripping gas and energy exchange pump gas.
[4] A minimal capital cost was allocated to all projects to consider cost of engineering studies
[5] Assumed 100% reduction of stripping gas
[6] Assumed recovered gas is recycled to inlet of facility. No fuel gas replacement.
[7] Assumed fuel gas savings limited by requirements of reboiler burner
[8] Assumed all recovered gas would replace fuel gas beyond the reboiler burner (e.g. compressor engines)

6. Conclusions and Recommendations for Future Work

In this report, a comprehensive review of the potential for methane emissions reductions from glycol dehydration and refrigeration facilities was completed. The report reviews the methodologies that are in use to obtain accurate estimates of methane emissions from these process units. It can be concluded that for TEG dehydration facilities, both Aspen HYSYS v9 and v10 (using the Glycol Property Package) and Glycalc can predict methane concentration in the rich glycol stream accurately. GlyCalc lacks the flexibility to examine different process configurations and the possibility to compare the results to available data at different pressures and temperatures as well as a reduced set of results that can be valuable in the determination of the technology options (e.g. reboiler duty calculations). In addition, HYSYS provides the flexibility to constantly improve the VLE predictions by changing the thermodynamic parameters of different property packages. For refrigeration facilities, Aspen HYSYS v9 and v10 (using the property package NRTL-PR) offers better results than Glycalc in terms of predicting two distinct liquid phases at all conditions. A correlation approach has been developed by Process Ecology that offers a promising alternative for high-level evaluations.

With an accurate process simulation model available, the sensitivity of key operating parameters on methane emissions was evaluated for alternative facility configurations. Key operating parameters that determine the quantity of methane venting from these facilities include the glycol circulation rate, the use of energy exchange pumps, and use of stripping gas and system pressure. Other operating parameters have minor contributions to methane emissions.

A number of technologies are available to mitigate methane emissions from glycol dehydration plants. Some of the options require relatively low-cost optimization projects to determine optimal circulation rates, stripping gas reduction/elimination and reboiler optimization. These can offer significant reductions in methane emissions while simultaneously reducing operating costs. These optimization options should always be considered before evaluating other technologies.

It is noted that the reported marginal abatement costs represent a single scenario which, although useful, cannot represent the wide variability of scenarios found in the upstream oil & gas industry. Future work should consider the use of probability distributions in the population of dehydrators, particularly in Western Canada to identify the ranges where the ranking of options may change due to facility size, operating pressures, and other plant characteristics. In addition, it is noted that technology providers continue improving their offerings and, in some cases, costs are expected to come down with increasing industry experience. Similarly, new technologies are being introduced to the industrial market for emissions reductions and all these would need to be evaluated on a continuous basis.

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